## Appendix A. Impacts of Petroleum Reduction Strategies on the California Economy (by Peter Hess and Peter Berck, University of California, Berkeley)

### A.1 Introduction

This appendix presents the methodology and results of assessing the impacts of petroleum reduction strategies on the California economy. Methodology is discussed first, then results.

The methodology employed is computable general equilibrium (CGE) modeling. CGE models are designed to captures the fundamental economic relationships between producers, consumers, and government. The models are "computable" because numeric solutions are found using computers rather than solved for algebraically. They are "general" in the sense that all markets and all income flows in the economy are accounted for. They reflect "equilibrium" insofar as prices adjust to equilibrate the demand for and supply of goods, services, and factors of production (labor and capital) the model.

The specific model employed here is a modified version of E-DRAM (Environmental-Dynamic Revenue Analysis Model). E-DRAM was built for the California Environmental Protection Agency's Air Resources Board (ARB) by researchers at the University of California, Berkeley (UCB). E-DRAM evolved from DRAM (Dynamic Revenue Analysis Model), which was developed jointly by the California Department of Finance (DOF) and Berkeley researchers to perform dynamic revenue analyses of proposed legislation as mandated by California State Senate bill 1837 in 1994. Much of the description of E-DRAM below is closely adapted from Berck, et al. (Summer 1996), which henceforth will be referred to as the DRAM Report.[1]

The remainder of this introduction is a non-technical description of E-DRAM. Section A.2 outlines modifications made to E-DRAM for this project. Section A.3 presents baseline solutions to the model for the years 1999, 2020, and 2050. Section A.4 evaluates various policy scenarios in 2020 and 2050. Section A.5 analyses the sensitivity of the results to select model parameters. Section A.6 offers concluding remarks.

#### A.1.1 A Description of the E-DRAM Model

E-DRAM describes the relationship among California producers, California households, California governments, and the rest of the world. Rather than tracking each individual producer, household, or government agency in the economy, however, E-DRAM combines similar agents into single sectors. Constructing a cogent sectoring scheme, the first step of model construction, is discussed immediately below; this discussion is followed by a description of the key agents in the economy – producers and consumers.

[1] The DRAM Report, *Dynamic Revenue Analysis for California* (Berck, *et al.*, Summer 1996), is available at www.dof.ca.gov/HTML/FS_DATA/dyna-rev/dynrev.htm.

#### A.1.1.1 Aggregation and Data Sources

E-DRAM, like all other empirical economic models, treats aggregates rather than individual agents. This is done both to provide focus for the analysis and contain the number of variables in the model. Constructing a cogent aggregation (or sectoring) scheme is critical in the development of a CGE model because it determines the flows that the model will be able to trace explicitly. For the E-DRAM model, the California economy has been divided into 93 distinct sectors: 29 industrial sectors, 2 factor sectors (labor and capital), 9 consumer good sectors, 7 household sectors, 1 investment sector, 45 government sectors, and one sector representing the rest of the world. The complete details of the sectoring are given in Chapter II of the DRAM Report.

For industrial sectoring purposes, all California firms making similar products are lumped together. The agriculture sector, for example, contains all California firms producing agricultural products. The output value of that sector is the value of all crops produced by California growers. A sector's labor demand is the sum of labor used by all firms in the sector. Along with agriculture, there are 28 other producer aggregates in the model. These aggregates generally represent the major industrial and commercial sectors of the California economy, though a few are tailored to capture sectors of particular regulatory interest. For instance, production of internal combustion engines and consumer chemicals are each delineated as distinct sectors at the request of ARB.[2]

Data for the industrial sectors originates from the U.S. Department of Commerce's Bureau of Economic Analysis (BEA), and is based on the Census of Business – a detailed survey of U.S. companies conducted every five years.[3] The survey contains information about intermediate purchases, factor (labor, capital, land and entrepreneurship) payments, and taxes. Although quite extensive, the survey only allows inference about groups of firms at the national level. The conversion of national data to updated California data is accomplished using a combination of state level employment data and estimates from DOF's econometric modeling.

Like firms, households are also aggregated. California households are divided into categories based upon their income. There are seven such categories in the model, each one corresponding to a California Personal Income Tax marginal tax rate (0, 1, 2, 4, 6, 8, and 9.3 percent). Thus, the income from all households in the one-percent bracket is added together and becomes the income for the “one-percent” household sector. Similarly, all expenditure on agricultural goods by the one-percent households is added and becomes the expenditure of the one-percent household sector on agricultural goods. Total household expenditure on agricultural goods is the sum of expenditures by all seven household sectors. Household income data come from the California Franchise Tax Board Personal Income Tax “sanitized” sample. Data on consumption by income class is derived from national survey data.

[2] The alcohol, tobacco, and horse racing sector, distinct in DRAM, is been folded into the foods sector in the latest version of E-DRAM.

[3] The survey is conducted in years ending in 2 and 7 and data is released after processing. E-DRAM uses data from the 1997 release, which contains processed 1992 survey data.

The government sectors in DRAM are organized so that both government revenue flows and expenditure flows are traced explicitly. The DRAM includes 45 government sectors: 7 federal, 27 state, and 11 local. Government sector data is culled from published federal, state, and local government reports.

#### A.1.1.2 Producers and Households

Fundamental to the California economy, and hence E-DRAM, are the relationships between the two principal types of economic agents – producers and households.

Producers, also known as firms, are aggregated into industrial sectors, and each sector is modeled as a competitive firm. For instance, the output of all of California's agricultural firms is modeled as coming from a single entity, the agriculture sector. Each sector takes the price that it receives for its output and the prices that it pays for its inputs (capital and labor, called "factors of production," and other inputs, called "intermediate goods") as fixed. This is the competitive model: producers do not believe that their decisions have any effect on prices. Each producer is assumed to choose inputs and output to maximize profits. Inputs are labor, capital, and intermediate goods (outputs of other firms). Thus, the producer's supply of output is a function of price and the producer's demand for inputs is a function of price. More information on producers is provided in Chapter IV of the DRAM Report.

Households make two types of decisions: they decide to buy goods and services; they also decide to sell labor and capital services. They are assumed to make these decisions in the way that maximizes their happiness (called "utility" in the economics literature). Like firms, they take the prices of the goods that they buy and the wage of the labor that they sell as fixed. In addition to their labor income, households receive dividends and interest from their stocks and bonds and other ownership interests in capital.

Households' supply of labor, as a function of the wage rate, is called the "labor-supply function." A more detailed description of the supply of labor is given in Chapter VII of the DRAM Report.

Households' demand for goods or services, as a function of prices, is simply called the "demand function." A more detailed description of the demand for goods and services is given in Chapter III of the DRAM Report, as well as in *Estimation of Household Demand for Goods and Services in California's Dynamic Revenue Analysis Model*, (Berck, Hess, and Smith, Sept. 1997) currently available at www.are.berkeley.edu/~phess/demand.pdf. The latter explains how the distribution of household spending across the 29 industrial sectors via the nine consumer goods sectors is based on analysis of U.S. Bureau of Labor Statistics' Consumer Expenditure Survey data.

#### A.1.1.3 Equilibrium

So far, two types of agents have been described: firms and households. It remains to be explained how these agents relate. They relate through two types of markets: factor markets and goods-and-services markets. Firms sell goods and services to households on the goods-and-services markets. Households sell labor and capital services to firms on the factor markets. There is a price in each of these markets. There is a price for the output of each of the 29 industrial sectors. There is a price for labor, called the "wage," and a price for capital services, called the “rental rate.” Equilibrium in a market means that the quantity supplied (which is a function of price) is equal to the quantity demanded (which is also a function of price) in that market. Equilibrium in the factor markets for labor and capital and in the goods-and-services markets for goods and services defines a simple general equilibrium system. That is, there are 31 prices (the wage, the rental rate, and one for each of the 29 goods made by the 29 sectors) and these 31 prices have the property that they equate quantities supplied and demanded in all 31 markets. They are market-clearing prices.

These relationships are shown in more detail in Figure A-1, called a “circular-flow diagram.” The outer set of flows, shown as solid lines, are the flows of “real” items, goods, services, labor, and capital. The inner flows, shown as broken lines, are monetary flows. Thus, firms supply goods and services to the goods-and-services market in return for revenues that they receive from the goods-and-services markets. Firms demand capital and labor from the factor markets and in return pay wages and rents to the factor markets.

Households, the other type of agent in a simple model, buy, or in economic parlance, demand, goods and services from the goods-and-services markets and give up their expenditure as compensation. They sell capital and labor services on the factor markets and receive income in exchange.

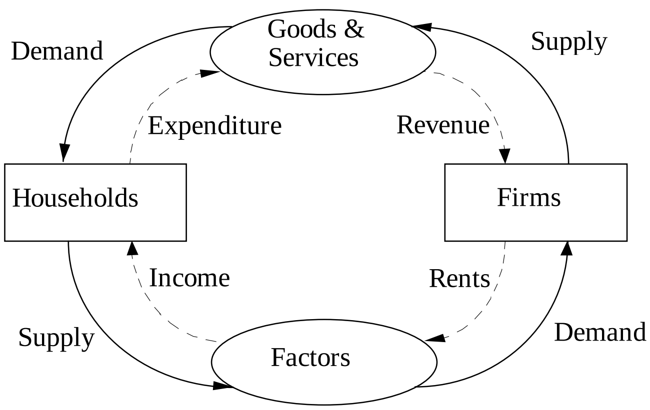


**Figure A-1. The Basic Circular-Flow Diagram**

### A.1.1.4 Intermediate goods

The economy of California is far more complex than that shown in Figure A-1. There are not only final goods-and-services markets but also intermediate goods markets in which firms sell to firms. A typical example of this would be chemicals sold to agricultural firms. The final output of the chemical industry (perhaps fertilizer) is said to be an intermediate good in the agricultural industry. This type of market is demonstrated in Figure A-2. Here, part of the supply of a firm (chemical industry in the example) is not sold to households but rather to another firm in exchange for revenue. From the other firm’s point of view, it buys an input to production from a firm rather than from a household. The expense of buying the input is a cost of production.

Chapter IV of the DRAM Report contains the model specification for these types of transactions, which are based upon a national input-output (I-O) table.

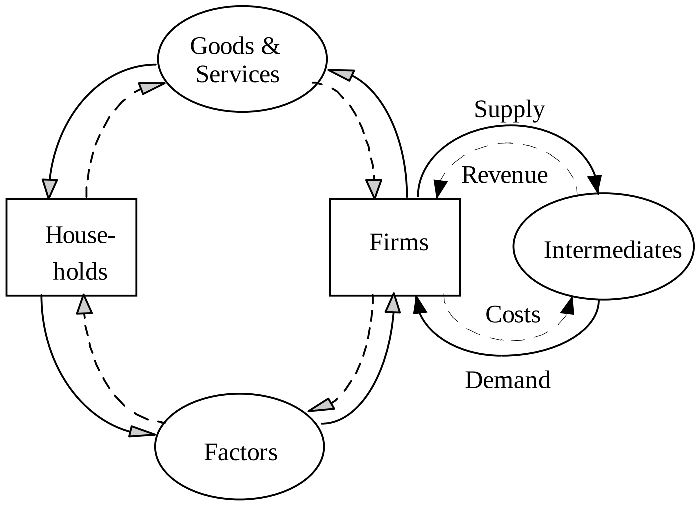


**Figure A-2. The Circular-Flow Diagram with Intermediate Goods**

#### A.1.1.5 Rest of the World

California is an open economy, which means that it trades goods, services, labor, and capital readily with neighboring states and countries. In this model, all agents outside California are modeled in one group called "Rest of World (ROW)." No distinction is made between the rest of the U.S. and foreign countries. California interacts with two types of agents: foreign consumers and foreign producers. Taking the producers first, Figure A-3 shows that the producers sell goods on the (final) goods-and-services markets and on the intermediate markets, i.e., they sell goods to both households and firms. The model takes these goods as being imperfect substitutes for the goods made in California. Agricultural products from outside of California (e.g., feed grains, bananas) are taken as being close to, but not identical to, California-grown products (e.g., avocados, fresh chicken). The degree to which foreign and domestic goods substitute for each other is very important, and the evidence is described in Chapter V. Foreign households buy California goods and services on the goods-and-services markets. They and foreign firms both can supply capital and labor to the California economy, and domestic migration patterns are described in Chapter VIII of the DRAM Report.

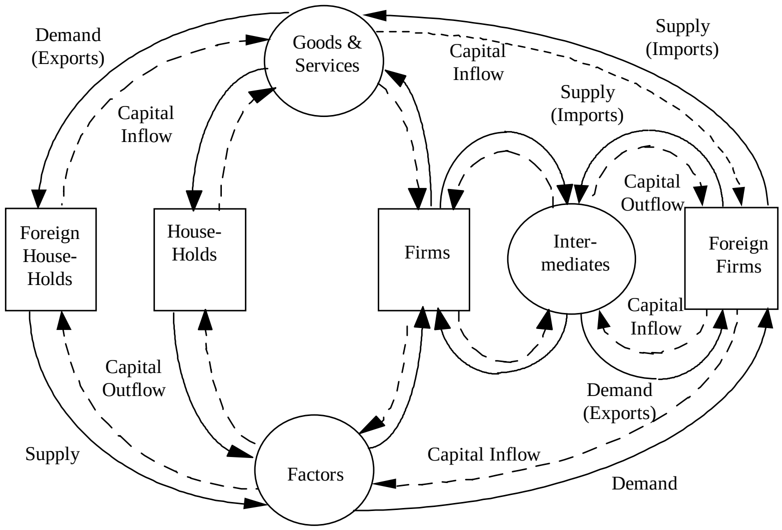


**Figure A-3. The Circular-Flow Diagram with Intermediate Goods and Trade**

#### A.1.1.6 Government

Finally, government is considered. Combining the taxing and spending effects of the three levels of government (federal, state, and local) gives the additional flows in Figure A-4. Beginning at the top, the figure shows that government buys goods and services and gives up expenditure. It supplies goods and services for which it may or may not receive revenue. Government also supplies factors of production, such as roads and education. The model does not currently include goods such as K-12 education as such goods are not always traded in organized markets. Government also makes transfers to households, which are not shown in the diagram. The middle section of the diagram shows the myriad of ways in which government raises revenue through taxation. Chapter II of the DRAM Report includes a detailed description of the government activities in the model.

#### A.1.1.7 Data Organization: The Social Accounting Matrix

The first step in constructing a CGE model is to organize the data. The traditional approach to data organization for a CGE model is to construct a Social Accounting Matrix (SAM). A SAM is a square matrix consisting of a row and column for each

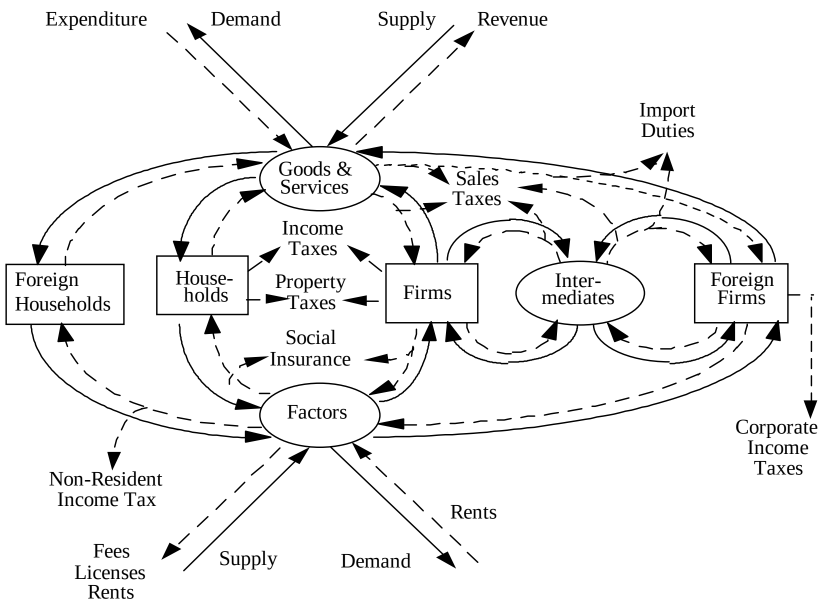


**Figure A-4. The Complete Circular-Flow Diagram**

sector of the economy. Each entry in the matrix identifies an exchange of goods and services purchased by one sector from another sector (or itself). The entries along a row in the SAM show each payment received by that particular row sector from each column sector. Summing across the row gives total payments made to that row sector by all column sectors. The entries down a column in the SAM show the expenditures made by that particular column sector to all row sectors. Summing down a column gives total expenditures by that column sector to all row sectors. For accounting purposes, a SAM must "balance," i.e., the each row sum and corresponding column sum must be equal. This balancing ensures that no money "leaks" out of the economy, i.e., that all money received by firms (row sum) is spent by them (column sum).

### A.1.2 Regional and National Model Differences

There have been hundreds of CGE models built and used for analyzing public policy at the national and international level. Regional, or sub-national, CGE models are very similar in design to national and international models, but exhibit major differences in several key assumptions. The seven most important differences between national and regional CGE models are discussed below.

The first, and maybe most important, difference is that regional CGE models do not require that regional savings equal regional investment. When Californians save more than California investors want to use, excess savings flow out of the state. When the converse is true, savings flow into the state. Rational economic agents would not accept less interest on their savings from California investors if higher interest rates were available in other states or countries.

Conversely, rational investors in California would not pay higher interest for the use of Californian savings if other states or countries offered lower rates.

The second difference is that regional economies trade a larger share of their output. Therefore, trade is more important in regional models. Note that interstate trade is part of the Rest of World for California but ignored in national considerations of trade.

The third difference is that regional economies face larger and more volatile migration flows than nations. Regional and international migration to California is a major factor in the State's economy.

The fourth difference between national and regional CGE's is that regional economies have no control over monetary policy. The Federal Reserve is responsible for monetary policy and is a national institution.

The fifth difference is that in regional models taxes are interdependent through deductibility. Some local taxes are deductible from incomes subject to California Personal Income Taxes and Bank and Corporation taxes. Some local and state taxes are deductible from incomes subject to Federal Personal Income Tax and may be eligible for deduction from corporate incomes for federal purposes. In E-DRAM, the personal tax deductibility is explicitly modeled. Since corporate deductibility is more uncertain and since the apportionment rules may reduce the connection to federal corporate taxes, corporate deductibility has not been included in E-DRAM.

Sixth, while good data for a CGE are hard to find at the national level, in many cases they are nonexistent for regional economies. The E-DRAM uses published economic and statistical literature to simulate much of the data important to our model. In some cases, such as labor supply, a wide variety of results are presented in the literature. This problem is addressed in three ways: (1) values are chosen so as to avoid the extremes, (2) the model is tested to determine the degree to which results are dependent upon our assumptions (this process is called "sensitivity analysis"), and (3) the use of published literature, especially of national results, has been minimized.

Seventh, the California CGE differs from a national CGE in that California faces a balanced-budget requirement. Even if this is ignored in the short run, bond markets tend to reflect this fact. When California issued bonds to cover short-term deficit spending in the early 1990s, bond ratings forced up the cost of borrowing. Ultimately, California would face unreasonable borrowing costs should it decide to maintain this level of borrowing.

### A.1.3 Other Considerations and Model Building

The CGE models are not forecasting models; they are calibrated to reproduce a base year. In the case of E-DRAM, the model is constructed to exactly reproduce the economic conditions of fiscal year 1998/99. Of course, there are forecasting models. However, such models typically do not have the level of detail needed to examine dynamic policy effects. Given the paucity of California-specific data, it seems a better compromise to use a forecasting model, such as the one maintained by DOF, to set a base case and then use a policy model, such as DRAM, to analyze deviations from that case.

The E-DRAM model incorporates two assumptions that require some comment. It assumes competitive behavior in all private sectors. This is a good first approximation, particularly at the level of a sector. The alternative, oligopoly behavior, may well be present, but the degree of markup of price over marginal cost is not likely to be significant. The second assumption is that involuntary unemployment is constant. This is unlikely to be strictly true. The model has voluntary unemployment, which are agents deciding to work less when the wage is lower. This assumption is common to all equilibrium models. Technical issues of model closure are described in Chapter IX of the DRAM Report.

Once the major agents in the economy have been identified and the relationship between these agents has been specified, the model can be built. In E-DRAM, the algebraic representation of the relationships between the agents in the California economy is achieved with General Algebraic Modeling System (GAMS). The model currently has 1,100+ equations, exclusive of definitions and of the code to read in and organize the data. All of the model's equations and GAMS code are detailed in Chapter X.

### A.1.4 Further Documentation

Fuller description of common features shared by E-DRAM and DRAM is available in the report cited above (see footnote 4). The primary contents of that report, the presentation of which mirrors the sequence of tasks involved in building DRAM, are as follows. In Chapter II of the DRAM Report, the major agents in the economy are identified and aggregated into sectors. These aggregates are constructed to focus the model on the major industries, taxpayers, and government agencies in the California economy. Data sources are also identified.

Chapters III through VIII of the DRAM Report review the literatures, functional forms, and elasticities relevant to the six primary behavioral equations that link all the various sectors of the model and drive its results. Chapter III of the DRAM Report reviews the literature on the economic behavior of households with respect to consumption and savings decisions. The literature on the production decisions of firms is examined in Chapter IV of the DRAM Report. Chapter V of the DRAM Report summarizes the literature on international and interregional trade. Investment theory is discussed in Chapter VI of the DRAM Report. Chapter VII of the DRAM Report covers the literature on regional labor-supply response to taxation and economic growth, while the literature on migration and economic growth is examined in Chapter VIII of the DRAM Report.

After establishing the sectoring scheme, data sources, and behavioral equations for the model, all that remains before the actual model can be built is a description of the model-closure rules. Closure rules concern the mathematics of insuring that a solution exists to the 1,100+ equations of the model. Model closure is developed in Chapter IX of the DRAM Report.

Chapter X of the DRAM Report describes the mathematical and corresponding GAMS notation for each equation in DRAM. It is a technical description of the complete California Dynamic Revenue Analysis Model.[4, 5]

[4] See Berck, Hess, and Smith (Sept. '97) for revisions to the consumer demand portion of the model.

Chapter XI of the DRAM Report presents some preliminary sensitivity analyses.

Appendices follow Chapter XI of the DRAM Report. They include the original literature search by Dr. Berck and Mr. Dabalen in the Summer of 1995, explanations of notational methods used, lists of parameter and variable names used in the mathematical and software input files, and printed copies of the input files themselves.

## A.2 Model Enhancements

For examining petroleum dependency issues in particular, the E-DRAM built for ARB as described in Berck and Hess (Feb. 2000) is enhanced in three ways. First, Petroleum sector data is modified. Second, the 1998/1999 base year model is extrapolated out to 2020 and 2050 based on state population, personal income, and industry-specific forecasts. Third, parameters to adjust for technological change in the form of increased fuel efficiency and fuel displacement are incorporated into the model. Each of these enhancements is discussed in turn in the subsections below.

### A.2.1 Petroleum Sector Base Data Modification

As indicated in Section A.1.1.1, E-DRAM's original industrial accounts are national accounts scaled to the state level using California employment data. These accounts have been reconciled with more California-specific Petroleum sector figures provided by TIAX in consultation with ARB, the California Energy Commission (CEC), and the Berkeley team.

TIAX estimated California refinery flows from EIA data.[6] A summary of these data for 1999 is shown in Table A-1. Several assumptions were made to get both specific California data and data for California supplies to Nevada and Arizona. First, TIAX assumed that California refining capacity and products are 72 percent of PAD V (28 percent is associated primarily with refining in Washington). Second, we also assumed that California refineries supply 80 percent of Nevada's needs and 50 percent of Arizona's needs. Prices for products indicated in Table A-1 are actual 1999 prices as reported by EIA. For example, average crude oil price was $17.81/bbl in 1999 and average finished motor gasoline price was $1.30/gal.

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[5] Modification of equations from DRAM to E-DRAM are discussed in *Developing a Methodology for Assessing the Economic Impacts of Large Scale Environmental Regulations* (Berck and Hess, Feb. 2000). Changes introduce parameters that facilitate running policy scenarios as some combination of price, intermediate good, and/or investment changes.

[6] Energy Information Administration, Office of Oils & Gas, U.S. DOE, *Petroleum Supply Annual 1999,* Vol. 1, June 2000 (www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum supply_annual/psa_volume 1/psa_volume1.html)

## Table A-1. Summary of California Supply and Demand for Refinery Products

| Description | 1999 | | 2020 | | 2050 | |
|---|---|---|---|---|---|---|
| | 000 bbls | $ million | 000 bbls | $ million | 000 bbls | $ million |
| **Imports to California** | | | | | | |
| Crude oil | 391,395 | 6,971 | 608,140 | 13,683 | 698,236 | 15,710 |
| Natural gas liquids | (1) | — | — | — | — | — |
| Other liquids (unfinished oils and gasoline blend components like oxgenates) | 29,227 | 1,228 | 37,979 | 1,595 | 75,959 | 3,190 |
| Refined products | 64,514 | 2,723 | 291,000 | 15,725 | 1,192,500 | 64,438 |
| Total Import Value | | 10,921 | | 31,003 | | 83,339 |
| **California Oil Production** | 273,019 | 4,862 | 90,096 | 2,027 | — | — |
| Total Input to California | | 15,784 | | 33,030 | | 83,339 |
| **California Transportation Consumption** | | | | | | |
| Finished motor gasoline | 335,633 | 18,364 | 463,151 | 31,902 | 745,648 | 51,360 |
| Distilled fuel oil | 64,078 | 3,199 | 128,190 | 8,884 | 261,128 | 18,096 |
| Residual fuel oil | 27,881 | 317 | 68,642 | 987 | 124,336 | 1,788 |
| Jet fuel | 98,673 | 2,383 | 218,894 | 6,680 | 596,829 | 18,213 |
| Liquefied petroleum gases | 384 | 15 | 592 | 30 | 592 | 30 |
| Other | 3,796 | 148 | 5,236 | 258 | 5,236 | 258 |
| California Demand | 530,445 | 24,427 | 884,705 | 48,740 | 1,733,769 | 89,745 |
| **California Other Consumption** | | | | | | |
| Finished motor gasoline | 2,158 | 118 | 2,697 | 186 | 4,342 | 299 |
| Distillate fuel oil | 10,584 | 328 | 16,421 | 1,138 | 33,451 | 2,318 |
| Residual fuel oil | 684 | 12 | 1,404 | 30 | 2,544 | 54 |
| Jet fuel | — | — | — | — | — | — |
| Liquefied petroleum gases | 11,787 | 374 | 14,630 | 586 | 14,630 | 566 |
| Other | 62,101 | 3,391 | 85,146 | 5,873 | 85,146 | 5,873 |
| California Demand | 87,314 | 4,222 | 120,300 | 7,813 | 140,114 | 9,120 |
| **Exports from California** | | | | | | |
| Crude oil | 35,610 | 634 | — | — | — | — |
| Refined products | 62,425 | 2,439 | 69,292 | 3,420 | 69,292 | 3,420 |
| California production to Arizona, Nevada for transportation and other | | | | | | |
| Finished motor gasoline | 44,908 | 2,457 | 61,932 | 4,266 | 99,707 | 6,868 |
| Distillate fuel oil | 18,054 | 901 | 34,968 | 2,423 | 71,231 | 4,936 |
| Residual fuel oil | 114 | 1 | 280 | 4 | 506 | 7 |
| Jet fuel | 11,497 | 278 | 25,504 | 778 | 69,538 | 2,122 |
| Liquefied petroleum gases | 3,179 | 127 | 3,976 | 201 | 3,976 | 201 |
| Other | 7,268 | 284 | 9,969 | 492 | 9,969 | 492 |
| Out of State Demand | 85,019 | 4,048 | 136,628 | 8,164 | 254,928 | 14,626 |
| Export Value | | 7,121 | | 11,584 | | 18,046 |
| Total Output | | 33,987 | | 63,744 | | 111,211 |

Estimates for 2020 and 2050 were obtained by first determining the overall demand for finish products. This was estimated from the CEC projections of baseline fuel demands (CEC, 2001). In this report, fuels are projected to grow at the following annual rates:

| Product | % Growth Rate/yr |
|---|---|
| Gasoline | 1.6 |
| Diesel | 2.4 |
| Jet | 3.4 |

We also assumed a nominal growth rate of 2 percent per year for residual and 1 percent per year for LPG and other products. The California growth rates were also applied to Nevada and Arizona.

Based on the total products supplied in 2020 and 2050, we then estimated how the refineries would produce these fuels. Several assumptions were used to make these predictions. California refinery capacity was assumed to grow at 0.5 percent per year through 2020 (Stillwater). This adds about 11 percent to the 1999 capacity of about 628.8 million barrels. After 2020 the capacity was held fixed and increase demand had to be met with importing refined products.

California oil production was assumed to decline from 1999 levels of 273 million barrels to 90 million barrels in 2020 and no in-state production in 2050. This estimate was based on linear extrapolation of either historical production or reserves. Either of these indicated California production being eliminated in the 2030-2040 time frame. Also, Alaska production (assuming no new drilling) declines to zero in the 2020-2030 time frame. Thus, California will be far more dependent on foreign oil supplies in the post 2020 years. 2020 and 2050 prices were also determined or scaled from CEC projections. CEC projects crude oil prices at $22.50/bbl and gasoline at $1.64/gallon and diesel at $1.65 gallon. So the prices in Table A-1 are comparable for 2020 and 2050 and are higher than 1999 by about the ratio of $22.50 to $17.81.

There are several interesting trends suggested in the data shown in Table A-1. California will be importing more crude in the out years due to dwindling in-state production. In 1999, crude imports (including mostly Alaska) were 391 million barrels. This will grow to 698 million barrels in 2050 and this supply will all have to come from foreign sources. In 1999, California imported 64.5 million barrels of refined products, which will grow to 1.19 trillion barrels in 2050.

Table A-2 itemizes our estimate of California refinery supply and demand expressed in dollars. This also shows in the out years that California will be much more dependent on imported refined products.

**Table A-2. Estimate of Supply and Demand Balance for California Refineries**

| Description | 1999 $ million | 2020 $ million | 2050 $ million |
|---|---|---|---|
| Supply California refineries | 32,413 | 52,413 | 52,483 |
| Refined products imported | 2,723 | 15,725 | 64,438 |
| Total demand | 35,136 | 68,137 | 116,922 |
| California | 28,649 | 56,553 | 98,876 |
| Export to Arizona, Nevada | 4,048 | 8,164 | 14,626 |
| Export from refineries | 2,439 | 3,420 | 3,420 |
| Crude imports | 6,971 | 13,683 | 15,710 |
| Supply | 32,413 | 52,413 | 52,483 |
| Demand | 35,136 | 68,137 | 116,922 |
| Import of refined products | (2,723) | (15,725) | (64,438) |

Modifications to the petroleum sector 1999 base data are as follows. First, E-DRAM's original petroleum sector (PETRO) import and export figures were replaced with those provided by TIAX.[7] Petroleum exports from California, as recorded in the (PETRO, ROW) cell of the SAM, were decreased from $11 billion down to $6.5 billion.[8] Petroleum imports to California, as recorded in the (ROW, PETRO) cell of SAM, were increased from $0.5 billion up to $2.7 billion.

Second, E-DRAM's California petroleum demand was raised to match TIAX's California petroleum demand estimate by increasing in-state consumer demand for petroleum (CFUEL).[9] Operationally, this was achieved by increasing the SAM cell (PETRO, CFUEL) from $6.3 billion to $13.7 billion. For consistency, this change was traced through household (HOUSE#) spending on CFUEL by raising each SAM (CFUEL, HOUSE#) cell by 20 percent. Increased fuel spending was offset via 0.8-1.6 percent (depending on each household sectors' overall expenditure levels) spending cuts applied uniformly across the other eight consumer good sectors.

Third, E-DRAM's petroleum supply was raised to equal California demand ($28.6 billion) plus exports from California ($6.5 billion) minus imports to California ($2.7 billion) as calculated from the revised numbers above. This supply shift was implemented by increasing petroleum sector inputs (intermediates, factors, and taxes thereon) by 2.2 percent across the board.[10]

[7] Trade flow data is typically one of the weakest links in regional economic models.
[8] Following convention, matrix cells are referenced by (row name, column name).
[9] All adjustment came through the consumer sector due to perceived weakness in E-DRAM's household demand data vise-a-vise government and industry demand data and the relative strength of indications from outside sources that household consumption was higher than the model's original base data suggested.
[10] Production is constant returns-to-scale.

Once these changes were made, the 1999 SAM had to be re-balanced, that is the SAM needed to be adjusted so that the row and column totals were again the same. Re-balancing was done using a program written by Sherman Robinson and Moataz El-Said in November 2000.[11]

### A.2.2 Extrapolation from 1999 to 2020 and 2050

As discussed in Section A.1.3, E-DRAM is not a forecasting model, but rather a model constructed to exactly reproduce the economic conditions of fiscal year 1998/99. To answer questions concerning the impacts of petroleum dependency reduction strategies far into the future, E-DRAM must be augmented to reflect future conditions. To “re-base” E-DRAM, i.e., move from a model of the 1999 economy to models of the economy in 2020 and 2050, E-DRAM's input data must be modified to reflect economic conditions in those “out years.” The following process leaves the basic structure of economic relationships intact, while scaling up 1998/1999 monetary and employment data using state personal income, population, and industry-specific forecasts.

#### A.2.2.1 Incorporating General Growth Forecasts

The first step in re-basing E-DRAM is to forecast economic growth. Borrowing from the University of California, Los Angeles (UCLA) business forecast, an average annual growth rate of 2.84 percent was assumed for the years 2000 to 2020; an average annual growth rate of 2.58 percent was assumed for 2020 to 2050. Compounding these growth rates delivered scale factors for re-basing monetary flows recorded in the SAM. In re-basing from 1998/1999 to 2020, each 1999 SAM transaction – unless otherwise noted below – was scale up by a factor of 2.2515; in re-basing from 2020 to 2050, each 2020 SAM transaction – unless otherwise noted below – was scaled by a factor of 2.1520.[12]

The second, related, step in re-basing E-DRAM is to forecast population and/or employment growth. DOF projections suggest a California population growth rate of 1.36 percent annually. Compounding this rate delivered scale factors for re-basing employment data. In re-basing from 1998/1999 to 2020, each employment-by-industry cell in the 1999 MSC matrix (in the MSC input file) was scaled up by a factor of roughly 1.3; in re-basing from 2020 to 2050, the each employment-by-industry cell in the 2020 MSC matrix was scaled up by roughly 1.5.[13]

The third step in re-basing E-DRAM is to reconcile income and property tax accounts. Receipts scaled up via step one above, change model calculated rates – which act as incentives in

[11] The method is described in S. Robinson, A. Cattaneo and, M. El Said, *Updating and Estimating a Social Accounting Matrix Using Cross Entropy Methods.* TMD Discussion Paper No. 58, IFPRI, August 2000. (This paper was also to be published in Economic Systems Research, March/June 2001.)

[12] The UCLA forecast for state personal income (SPI) is $1.1 trillion in 2000 and implies an average annual SPI growth rate of 2.84% to 2012. Given that the 2000 SPI forecast is roughly 28% above the original 1998/1999 E-DRAM SPI level, and extrapolating the 2.84% growth rate out to 2020, each cell of the SAM – unless otherwise noted – was scaled up by $1.28*(1.0284)^{20} = 2.2515$ in re-basing the model from '98/'99 to 2020. Assuming 2.58% average annual SPI growth from 2020 to 2050 led to scaling each cell of the SAM – unless otherwise notes – by a by factor of $(1.0258)^{30} = 2.1520$.

[13] Scale factors for employment in the petroleum sector and the energy and mining sector were slightly lower, in accordance with growth forecasts for those industries (see next section).

economic decision making – when the population grows at a different pace than the economy as a whole. Rates and receipts are reconciled via tax adjustment parameter, TAXCVC (GI,H).[14]

#### A.2.2.2 Incorporating Petroleum Sector Forecasts

Petroleum sector and energy and mining sector (ENMIM), supply, demand, and trade flows were scaled according to TIAX's projections as detailed in Tables D-1 and D-2.[15]

#### A.2.2.3 1999 to 2020

TIAX projects demand (including exports) for California refined petroleum rising from $35.1 billion in 1999 to $68.1 billion in 2020, and California supply (excluding imports) rising from $32.4 billion to $52.4 billion over the same time period. Operationally, this meant increasing California refined petroleum demand (all cells, except ROW, in the PETRO row of SAM) by a factor of nearly 2, while increasing California refined petroleum supply (all cells, except ROW, in the PETRO column of SAM) by a factor of roughly 1.6 when re-basing E-DRAM from 1998/1999 to 2020.[16] The gap in domestic supply and demand was offset by higher net imports. Refined imports, SAM cell (ROW, PETRO), were raised from $2.7 billion in the 1999 SAM to $15.7 billion in the 2020 SAM; refined exports, SAM cell (PETRO, ROW) were raised from $6.5 billion to $11.6 billion.

TIAX projects California crude oil production dropping from roughly $4.9 billion in 1999 to roughly $2 billion in 2020. With crude oil accounting for 79 percent of energy and mining sector (ENMIN) output value in 1999, that sector's production was projected to be only 2.4 percent higher in 2020 than 1999.[17] Assuming ENMIN sector demand (including exports) grows at 2.84 percent annually along with rest of the economy, the resulting gap in domestic supply and demand was offset with higher imports. ENMIN sector imports, SAM cell (ROW, ENMIN), were raised from $17.5 billion in the 1999 SAM to $36.0 billion in the 2020 SAM.

Once these changes were made, the 2020 SAM was re-balanced using the cross entropy program written by Sherman Robinson and Moataz El-Said.

#### A.2.2.4 2020 to 2050

Gaps between supply and demand are more pronounced in the 2050 projections.

TIAX projects demand (including exports) for California refined petroleum rising from $68.1 billion in 2020 to $116.9 billion in 2050, and California supply (excluding imports) rising from $52.4 billion to only $52.5 billion over the same time period. Operationally, this meant increasing California refined petroleum demand (all cells, except ROW, in the PETRO row of

[14] GI indexes government income tax units, i.e., federal and state income tax as well as local property tax; H indexes household types (which, recall, are classified by income tax bracket).
[15] Capital stocks in the energy sectors were fixed to reflect capacity constraints.
[16] The increases in consumer petroleum demand, SAM cell (PETRO, CFUEL), was again translated through household sectors' increased expenditure on CFUEL and decreased expenditure on other consumer goods as discussed in Section A.2.1.
[17] The remaining 21% of the ENMIN sector was assumed to grow at the same rate as the rest of the economy, i.e., 2.84% annually.

SAM) by a factor of 1.775, while increasing California refined petroleum supply (all cells, except ROW, in the PETRO column of SAM) by a factor of roughly 1.008 when re-basing E-DRAM from 2020 to 2050.[18] The gap in domestic supply and demand was offset by higher net imports. Refined imports, SAM cell (ROW, PETRO), were raised from $15.7 billion in the 2020 SAM to $64.4 billion in the 2050 SAM; refined exports, SAM cell (PETRO, ROW) were raised from $11.6 billion to $18.0 billion.

TIAX projects California crude oil production dropping from roughly $2.0 billion in 2020 to zero in 2050. With crude oil accounting for 31 percent of energy and mining sector (ENMIN) output value in 2020, that sector's production was projected to be 19 percent higher in 2050 than 2020.[19] Assuming ENMIN sector demand (including exports) grows at 2.58 percent annually along with rest of the economy, the resulting gap in domestic supply and demand was offset with higher imports. ENMIN sector imports, SAM cell (ROW, ENMIN), were raised from $36.0 billion in the 1999 SAM to $57.0 billion in the 2020 SAM.

Once these changes were made, the 2050 SAM was re-balanced using the cross entropy program written by Sherman Robinson and Moataz El-Said.

### A.2.3 Adjusting for Technological Change

Parameters for modeling technological change built into the original E-DRAM were augmented for the current analyses.

As described in Berck and Hess (Feb. 2000), the original E-DRAM allows for changes in production technology. Each industrial sector in E-DRAM is implicitly characterized by a production function that relates output to factor (capital and labor) and intermediate inputs. Technological change is modeled by altering the relationships of input mix per unit of output as follows. Industry *J*'s demand for intermediates from industry *I* per unity of output is governed by production parameters AD(*I*,*J*), which are input-output coefficients calculated from primary data contained in the SAM. These coefficients can be altered via technology multiplier parameters REG1(*I*,*J*). Changing REG1(*I*, *'industry J label'* ) from its default setting of unity to 0.9, for example, simulates a technological change enabling one unit of industrial good *J* to be produced using only 90 percent of the intermediate inputs (from all 29 industries) previously required. Specifying AD(*'industry I label'*, *'industry J label'*) = 0.9, in contrast, simulates a technological change enabling one unit of good *J* to be produced using 90 percent of the intermediate inputs previously required from industry *I* (with inputs from the 28 other industries unchanged). See Section A.4 for implementation.

For the current project, an additional parameter is added to allow for technological changes in consumption. This new parameter is REG16(*I*,*C*), where *C* indexes the nine consumer good categories. REG16(*I*,*C*) is inserted into E-DRAM as a technology multiplier parameter wherever

[18] The increases in consumer petroleum demand, SAM cell (PETRO, CFUEL), was again translated through household sectors' increased expenditure on CFUEL and decreased expenditure on other consumer goods as discussed in Section A.2.1.
[19] The remaining 69% of the ENMIN sector was assumed to grow at the same rate as the rest of the economy, i.e., 2.58% annually.

parameter PHI(*I,C*) appears.[20] PHI(*I,C*) regulates the distribution of household spending on industry *I* via consumer good *C*. Changing REG16(*I*, *'consumer good C label'*) from its default setting of unity to 0.8, for example, simulates a technological change enabling one unit of consumer good *C* to be enjoyed using only 80 percent of the inputs previously required (from all 29 industries). Specifying REG16(*'industry I label'*, *'consumer good C label'*) in contrast, simulates a technological change enabling one unit of consumer good *C* to be enjoyed using 80 percent of the inputs previously required from industry *I* (with inputs from the other 28 industries unchanged). See Section A.4 for implementation.

## A.3 1999, 2020, and 2050 Base Case Models

Table A-3 displays selected input data and corresponding model output for the 1999, 2020, and 2050 base case models. Comparing the columns labeled "DATA" and "MODEL" for any given year indicates that the model is well calibrated, i.e., it produces model solutions that match the input data to within tenths or hundredths of one percent. Achieving such calibration is an essential starting point for policy analysis, as policy scenario results that differ from the base model by less than the level of calibration are not empirically significant.

Comparing across model years demonstrates how the economy grows by roughly the scale factors discussed in Section A.2.2.1. State output and personal income increase by factors of roughly 2.25 from 1999 to 2020 and 2.15 from 2020 to 2050, respectively, while state population and employment grow by factors of roughly 1.3 from 1999 to 2020 and 1.5 from 2020 to 2050. The petroleum (PETRO) and energy and mining (ENMIN) sectors both also grow by roughly the scale factors implemented.[21]

## A.4 Scenarios

The subsections below analyze four alternative strategies for reducing California's petroleum dependence. Each scenario is built around two elements: (1) reduced gasoline demand from improved light-duty vehicle fuel economy, and (2) diesel fuel displacement from gas-to-liquid (GTL) or Fischer Tropsch diesel fuels. The scenarios were constructed to try to "bound" the possible impacts to the California economy. Scenario 1 combines off-the-shelf fuel efficiency improvements in light-duty vehicles with a 33 percent blend of FTD in diesel fuel to meet ARB's future ULSD specification. Conversely, Scenarios 3 and 4 incorporate more aggressive and therefore more costly fuel efficiency or displacement options.

These strategies, developed in a collaborative process between ARB, CEC, and TIAX are summarized in Appendix B. Each strategy is described briefly and GAMS code for its implementation into E-DRAM presented. Select model output is given and discussed.

Each scenario is modeled and coded as some combination of increased transportation costs and altered – generally decreased – fuel costs. The rationale is that more efficient transportation is costlier to produce, but saves fuel.

[20] PHI(I,C) appears in equations 1.05 and 1.06.
[21] Small divergence between scaling input to the model and output from the model occur due to SAM balancing.

**Table A-3. Selected Input Data and Corresponding Model Output for the 1999, 2020, and 2050 Base Case Models**

| | 1999 | | 2020 | | 2050 | |
|---|---|---|---|---|---|---|
| | DATA | BASE MODEL | DATA | BASE MODEL | DATA | BASE MODEL |
| CA OUTPUT ($BILLION) | 1377.0067 | 1378.0905 | 3075.0665 | 3078.0223 | 6561.4202 | 6568.5732 |
| % CHANGE CA OUTPUT | | 0.08% | | 0.10% | | 0.11% |
| CA PERSONAL INCOME ($BILLION) | 891.6942 | 892.4894 | 2007.3821 | 2009.5373 | 4319.8863 | 4325.2331 |
| % CHANGE CA PERS. INC. | | 0.09% | | 0.11% | | 0.12% |
| CONSUMER PRICE INDEX (BASE=1) | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0001 |
| % CHANGE AGGREGATE CPI | | 0.00% | | 0.00% | | 0.01% |
| POPULATION (MILLION FAMILIES) | 23.1413 | 23.1431 | 30.7317 | 30.7362 | 46.0883 | 46.0978 |
| % CHANGE POPULATION | | 0.01% | | 0.01% | | 0.02% |
| WAGE INDEX (BASE = 100) | 100.0000 | 100.0517 | 100.0000 | 100.0688 | 100.0000 | 100.0880 |
| % CHANGE WAGE INDEX | | 0.05% | | 0.07% | | 0.09% |
| LABOR DEMAND (MILLIONS) | 14.0459 | 14.0483 | 18.6552 | 18.6605 | 27.9572 | 27.9673 |
| % CHNGE LABOR DEMAND | | 0.02% | | 0.03% | | 0.04% |
| RETURN TO K INDEX (BASE=100) | 100.0000 | 100.0060 | 100.0000 | 100.0067 | 100.0000 | 100.0075 |
| % CHANGE RETURN TO K INDEX | | 0.01% | | 0.01% | | 0.01% |
| CAPITAL STOCK ($100 BILLION) | 14.5720 | 14.5863 | 32.7161 | 32.7557 | 70.3030 | 70.4023 |
| % CHANGE CAPITAL STOCK | | 0.10% | | 0.12% | | 0.14% |
| ENMIN | | | | | | |
| OUTPUT ($BILLION) | 5.8738 | 5.8789 | 6.2035 | 6.2086 | 7.6830 | 7.6887 |
| % CHANGE OUTPUT | | 0.09% | | 0.08% | | 0.07% |
| JOBS (MILLIONS) | 0.0178 | 0.0178 | 0.0182 | 0.0182 | 0.0216 | 0.0216 |
| % CHANGE JOBS | | 0.16% | | 0.15% | | 0.14% |
| PRICE (BASE=1) | 1.0000 | 1.0001 | 1.0000 | 1.0001 | 1.0000 | 1.0000 |
| % CHANGE PRICE | | 0.01% | | 0.01% | | 0.00% |
| IMPORTS ($BILLION) | 17.5309 | 17.5404 | 35.9865 | 36.0105 | 57.3622 | 57.4093 |
| % CHANGE IMPORTS | | 0.05% | | 0.07% | | 0.08% |
| EXPORTS ($BILLION) | 0.4377 | 0.4375 | 1.0973 | 1.0965 | 2.6420 | 2.6396 |
| % CHANGE EXPORTS | | -0.06% | | -0.07% | | -0.09% |
| PETRO | | | | | | |
| OUTPUT ($BILLION) | 24.8013 | 24.8156 | 39.2783 | 39.3048 | 39.2124 | 39.2540 |
| % CHANGE OUTPUT | | 0.06% | | 0.07% | | 0.11% |
| JOBS (MILLIONS) | 0.0220 | 0.0220 | 0.0292 | 0.0292 | 0.0294 | 0.0295 |
| % CHANGE JOBS | | 0.09% | | 0.10% | | 0.15% |
| PRICE (BASE=1) | 1.0000 | 1.0001 | 1.0000 | 1.0001 | 1.0000 | 1.0000 |
| % CHANGE PRICE | | 0.01% | | 0.01% | | 0.00% |
| IMPORTS ($BILLION) | 2.8054 | 2.8058 | 15.6811 | 15.6834 | 63.6238 | 63.6368 |
| % CHANGE IMPORTS | | 0.01% | | 0.01% | | 0.02% |
| EXPORTS ($BILLION) | 6.4755 | 6.4746 | 11.9998 | 11.9979 | 19.1462 | 19.1419 |
| % CHANGE EXPORTS | | -0.01% | | -0.02% | | -0.02% |

Industries and households buy transportation and fuel. In E-DRAM, industries buy some vehicle engines directly, while households buy them indirectly via the consumer goods sectors. Industrial purchases from the engine (ENGIN) and petroleum (PETRO) sectors are recorded in SAM cells ('ENGIN', I) and ('PETRO', I), respectively. Households' purchases from the consumer transportation sector (CTRANS) are recorded in the SAM cells (I, 'CTRANS'). Households' purchases of petroleum via the consumer fuel sector (CFUEL) are recorded in SAM cells (I, 'CFUEL').

Following the explanation of technological change parameters in Section A.2.3, increases in consumer and industrial transportation costs are modeled using parameters REG16(*I, 'CTRNS'*) and REG1(*'ENGIN',I*), respectively. Decreases in consumer and industrial fuel costs are modeled using parameters REG16(*'PETRO', 'CFUEL'*) and REG1('PETRO', I), respectively. Switches from petroleum to hydrogen based fuels (scenario 3 only) are modeled as increases in REG1(*'ENMIN', 'PETRO'*), accompanied by offsetting increases in REG1(*'CHEMS', 'PETRO'*).[22]

The CEC estimates that residential use accounts for roughly 90 percent of gasoline consumption in the state. Hence, 90 percent of projected increases in engine costs are apportioned to household and 10 percent are apportioned to industries. Likewise, 90 percent of projected fuel savings are apportioned to households and 10 percent are apportioned to industries.

The following four subsections detail four alternative policy scenarios for reducing California's petroleum dependence. A short policy description, GAMS code that models the projected costs and benefits via the channels outlined immediately above, and select E-DRAM output along with corresponding analysis are presented for each.

### A.4.1 Scenario 1: EEA/Duleep Fuel Economy Improvements[23]

Scenario 1 is a combination of fuel efficiency measures applied to light-duty vehicles starting in 2008 and FTD blended with other diesel feedstocks at 33 percent to meet ARB's future ULSD specification. Table A-4 summarizes the costs and benefits of this combined strategy. Light-duty vehicle costs in 2020 and 2050 where taken from CALCARS analyses performed by CEC. The EEA/Duleep case phases in off-the-shelf fuel economy improvements in the early years of implementation and introduces higher fuel economy technologies in the later years. The benefits at the household level result from fuel savings associated with the higher fuel economy technologies. The estimates for 2020 and 2050 include vehicles that have been introduced earlier; that is the technology is applied to new vehicles starting in 2008 and continuous as other vehicles retire from the fleet. Thus, the cost and benefits are a "slice" in time of what the fleet would look like and what the costs would be. These costs were then input into the model to assess economic impact.

Scenario 1 is implemented in the following manner (see footnotes for actual GAMS code).

The cost of consumer transportation (CTRNS) increases by 90 percent of projected consumer cost. These additional costs are inserted such that the new, higher amount of consumer transportation spending is expressed as the appropriate multiple of old spending.[24]

The cost of industrial engines increases by 10 percent of the projected consumer cost, plus the commercial costs. These additional costs are inserted such that the new, higher amount of industrial spending on engines is expressed as the appropriate multiple of old spending.[25]

[22] This implementation assumes that the much the same fuel distribution system would be used regardless of the fuel variety.
[23] Numbers in the illustrative scenario coding correspond to 2020 cost/benefit projections.
[24] REG16(I,'CTRNS') = (SUM(J, SAM(J,'CTRNS')) + 0.9*1.961)/SUM(J, SAM(J,'CTRNS'));
[25] REG1('ENGIN',I) = (SUM(J,SAM('ENGIN',J)) + .1*1.961 + .125)/SUM(J,SAM('ENGIN',J));

**Table A-4. Estimated Economic Inputs for Scenario 1: EEA/Duleep Fuel Economy Improvements**

| Changes in Consumer Expenditures | Million 2002 $ | | Changes in Sector Revenue | Million 2002 $ | |
|---|---|---|---|---|---|
| | 2020 | 2050 | | 2020 | 2050 |
| Cost | | | Benefit | | |
| Household (inc. vehicle cost) | 1,460 | 4,900 | Vehicle Mfg. (inc. vehicle revenue) | 1,460 | 4,900 |
| Household (inc. PZEV cost) | 501 | 812 | Vehicle Mfg. (inc. PZEV revenue) | 501 | 812 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Total Cost | 2,087 | 5,858 | Total Benefits | 2,087 | 5,858 |
| Benefits | | | Cost | | |
| Household (dec. gasoline expenditure | 3,264 | 14,617 | Refiners (decrease in revenue) | 2,547 | 11,409 |
| | | | California Excise Tax (dec. revenue) | 358 | 1,604 |
| | | | Federal Excise Tax (dec. revenue) | 358 | 1,604 |
| Total Benefits | 3,264 | 14,617 | Total Costs | 3,264 | 14,617 |

90 percent of the projected savings from increased fuel efficiency accrue to consumers. These savings are inserted such that the new, lower amount of consumer fuel spending is expressed as the appropriate fraction of old spending.[26]

10 percent of the projected savings from increased fuel efficiency accrue to industry. These savings are inserted such that the new, lower amount of industrial spending on fuel is expressed as the appropriate multiple of old spending.[27]

Table A-5 compares selected results for base model and Scenario 1 runs of E-DRAM in both 2020 and 2050. Results show that scenario 1 slightly reduces state output (by 0.10 percent in 2020 and 0.17 percent in 2050) while slightly increasing state personal income (by 0.1 percent in 2050). *Real* personal income (what's reported in the table) rises while output falls because of increased consumer purchasing power due to improved fuel efficiency. Results indicate that the price of consumer fuel – interpreted as the price of vehicle miles traveled – is roughly 3 percent lower in 2020 and 7 percent lower in 2050 in Scenario 1 than in base.

Increased fuel efficiency reduces the demand for refined petroleum products. E-DRAM predicts petroleum sector output being 4 percent lower in 2020 and 16 percent lower in 2050 under Scenario 1 *vs.* base. Decreased petroleum sector output adversely affects upstream crude oil suppliers. The model predicts energy and mining sector output being 4 percent lower in 2020 and 16 percent lower in 2050 under Scenario 1 than base.

[26] REG16(I,'CFUEL') = (SUM(J, SAM(J,'CFUEL')) - .9*3.264 )/SUM(J, SAM(J,'CFUEL'));
[27] REG1('PETRO',I) = (SUM(J,SAM('PETRO',J)) - .1*3.264)/SUM(J,SAM('PETRO',J));

## Table A-5. Comparison of Selected Results for Base Model and Scenario 1 Runs of E-DRAM in Both 2020 and 2050

| | 2020 | | 2050 | |
|---|---|---|---|---|
| | BASE MODEL | SCNRIO1 | BASE MODEL | SCNRIO1 |
| CA OUTPUT ($BILLION) | 3078.0223 | 3074.9243 | 6568.5732 | 6557.2797 |
| % CHANGE CA OUTPUT | 0.10% | -0.10% | 0.11% | -0.17% |
| CA PERSONAL INCOME ($BILLION) | 2009.5373 | 2009.5213 | 4325.2331 | 4329.6794 |
| % CHANGE CA PERS. INC. | 0.11% | 0.00% | 0.12% | 0.10% |
| LABOR DEMAND (MILLIONS) | 18.6605 | 18.6767 | 27.9673 | 28.0326 |
| % CHNGE LABOR DEMAND | 0.03% | 0.09% | 0.04% | 0.23% |
| PRICE OF CFOOD | 1.0001 | 1.0001 | 1.0001 | 1.0000 |
| PRICE OF CHOME | 1.0000 | 1.0000 | 1.0001 | 0.9999 |
| PRICE OF CFUEL | 1.0000 | 0.9687 | 1.0000 | 0.9324 |
| PRICE OF CFURN | 1.0001 | 1.0001 | 1.0001 | 1.0000 |
| PRICE OF CCLOTH | 1.0001 | 1.0001 | 1.0001 | 1.0000 |
| PRICE OF CTRANS | 1.0000 | 1.0072 | 1.0001 | 1.0095 |
| PRICE OF CMED | 1.0001 | 1.0002 | 1.0001 | 1.0003 |
| PRICE OF CAMUS | 1.0000 | 1.0001 | 1.0001 | 0.9999 |
| PRICE OF COTHR | 1.0000 | 1.0000 | 1.0001 | 0.9999 |
| ENMIN | | | | |
| OUTPUT ($BILLION) | 6.2086 | 6.0575 | 7.6887 | 7.2328 |
| % CHANGE OUTPUT | 0.08% | -2.43% | 0.07% | -5.93% |
| IMPORTS ($BILLION) | 36.0105 | 34.8290 | 57.4093 | 52.2725 |
| % CHANGE IMPORTS | 0.07% | -3.28% | 0.08% | -8.95% |
| EXPORTS ($BILLION) | 1.0965 | 1.1122 | 2.6396 | 2.7452 |
| % CHANGE EXPORTS | -0.07% | 1.43% | -0.09% | 4.00% |
| PETRO | | | | |
| OUTPUT ($BILLION) | 39.3048 | 37.6902 | 39.2540 | 32.6620 |
| % CHANGE OUTPUT | 0.07% | -4.11% | 0.11% | -16.79% |
| IMPORTS ($BILLION) | 15.6834 | 15.5646 | 63.6368 | 62.1426 |
| % CHANGE IMPORTS | 0.01% | -0.76% | 0.02% | -2.35% |
| EXPORTS ($BILLION) | 11.9979 | 12.0739 | 19.1419 | 19.5219 |
| % CHANGE EXPORTS | -0.02% | 0.63% | -0.02% | 1.99% |
| ENGIN | | | | |
| OUTPUT ($BILLION) | 40.4675 | 40.5818 | 87.0335 | 87.2217 |
| % CHANGE OUTPUT | 0.05% | 0.28% | 0.05% | 0.22% |
| IMPORTS ($BILLION) | 9.0494 | 9.0815 | 19.4495 | 19.5153 |
| % CHANGE IMPORTS | 0.02% | 0.35% | 0.04% | 0.34% |
| EXPORTS ($BILLION) | 13.8359 | 13.7822 | 29.7408 | 29.6307 |
| % CHANGE EXPORTS | -0.03% | -0.39% | -0.05% | -0.37% |
| CHEMS | | | | |
| OUTPUT ($BILLION) | 30.2836 | 30.6482 | 64.9941 | 66.6697 |
| % CHANGE OUTPUT | 0.22% | 1.20% | 0.24% | 2.58% |
| IMPORTS ($BILLION) | 39.3028 | 39.2943 | 84.2137 | 84.1483 |
| % CHANGE IMPORTS | 0.01% | -0.02% | 0.02% | -0.08% |
| EXPORTS ($BILLION) | 2.0905 | 2.0910 | 4.6502 | 4.6542 |
| % CHANGE EXPORTS | -0.01% | 0.02% | -0.02% | 0.09% |
| FOODS | | | | |
| OUTPUT ($BILLION) | 92.9579 | 95.1127 | 200.2299 | 210.4874 |
| % CHANGE OUTPUT | 0.14% | 2.32% | 0.17% | 5.12% |
| APPAR | | | | |
| OUTPUT ($BILLION) | 25.9513 | 26.4969 | 55.8814 | 58.7842 |
| % CHANGE OUTPUT | 0.20% | 2.10% | 0.25% | 5.19% |
| MOTOR | | | | |
| OUTPUT ($BILLION) | 18.2243 | 18.1613 | 39.3478 | 39.1508 |
| % CHANGE OUTPUT | 0.23% | -0.35% | 0.24% | -0.50% |

Money freed from fuel expenditure is spent in other sectors. Scenario 1 raises both food (FOODS) and apparel (APPAR) sector output by roughly 2 percent over base in 2020 and by 5 percent over base in 2050.

Sectors such as motor vehicle manufacturing (MOTOR) that rely heavily on combustion engine inputs, see costs rise; thus their prices rise and output falls. The price of consumer transportation (CTRANS) rises 0.72 percent and 0.95 percent in 2020 and 2050, respectively, while motor vehicle sector output falls 0.35 percent and 0.50 percent in those same times.

### A.4.2 Scenario 2: ACEE-Advanced Fuel Economy Improvements

Scenario 2 is similar to Scenario 1 but incorporates more aggressive fuel economy technologies in light-duty vehicles. In this case, technology costs and benefits were determined from ACEEE analysis for advanced fuel economy improvements. It was assumed that these improvements would be implemented in all new light-duty passenger cars and trucks starting in 2008.

The ACEEE-Advance case is more aggressive in increasing fuel economy compared to the EEA/Duleep case and the ACEEE costs tend to be lower than those estimated by EEA. Further, the EEA technologies are phased in at a much slower penetration than those assumed in this scenario.

Table A-6 shows our estimates of the economic inputs for modeling. As indicated, costs are higher in 2020 compared to Scenario 1 primarily due to the high penetration rate. Likewise,

**Table A-6. Estimated Economic Inputs for Scenario 2: ACEE-Advanced Fuel Economy Improvements**

| Changes in Consumer Expenditures | Million 2002 $ | | Changes in Sector Revenue | Million 2002 $ | |
|---|---|---|---|---|---|
| | 2020 | 2050 | | 2020 | 2050 |
| Cost | | | Benefit | | |
| Household (inc. vehicle cost) | 4,197 | 6,794 | Vehicle Mfg. (inc. vehicle revenue) | 4,197 | 6,794 |
| Household (inc. PZEV cost) | 501 | 812 | Vehicle Mfg. (inc. PZEV revenue) | 501 | 812 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Total Cost | 4,824 | 7,752 | Total Benefits | 4,824 | 7,752 |
| Benefits | | | Cost | | |
| Household (dec. gasoline expenditure) | 9,284 | 19,746 | Refiners (decrease in revenue) | 7,246 | 15,411 |
| | | | California Excise Tax (dec. revenue) | 1,019 | 2,167 |
| | | | Federal Excise Tax (dec. revenue) | 1,019 | 2,167 |
| Total Benefits | 9,284 | 19,746 | Total Costs | 9,284 | 19,746 |

benefits are also considerably higher in 2020. At 2050 the two scenarios are more similar since EEA has fully phased in the higher fuel economy technologies and the ACEEE technologies are also fully phased in. Scenario 2 also includes the GTL or FTD blend as in Scenario 1.

Scenario 2 is implemented in the following manner.

The cost of consumer transportation (CTRNS) increases by 90 percent of projected consumer cost. These additional costs are inserted such that the new, higher amount of consumer transportation spending is expressed as the appropriate multiple of old spending.[28]

The cost of industrial engines increases by 10 percent of the projected consumer cost, plus the commercial costs. These additional costs are inserted such that the new, higher amount of industrial spending on engines is expressed as the appropriate multiple of old spending.[29]

90 percent of the projected savings from increased fuel efficiency accrue to consumers. These savings are inserted such that the new, lower amount of consumer fuel spending is expressed as the appropriate fraction of old spending.[30]

10 percent of the projected savings from increased fuel efficiency accrue to industry. These savings are inserted such that the new, lower amount of industrial spending on fuel is expressed as the appropriate multiple of old spending.[31]

Table A-7 compares selected results for base model and Scenario 2 runs of E-DRAM in both 2020 and 2050. Results show that Scenario 2 slightly reduces state output (by 0.26 percent in 2020 and 0.23 percent in 2050) while leaving state personal income essentially unchanged. *Real* personal income remains constant while output falls because of increased consumer purchasing power due to improved fuel efficiency. Results indicate that the price of consumer fuel – interpreted as the price of vehicle miles traveled – is roughly 9 percent lower in both 2020 and 2050 in Scenario 2 than in base.

Increased fuel efficiency reduces the demand for refined petroleum products. E-DRAM predicts petroleum sector output being 12 percent lower in 2020 and 23 percent lower in 2050 under Scenario 2 versus base. Decreased petroleum sector output adversely affects upstream crude oil suppliers. The model predicts energy and mining sector output being 7 percent lower in 2020 and 8 percent lower in 2050 under scenario two than base.

Money freed from fuel expenditure is spent in other sectors. Scenario two raises both food and apparel sector output by 6 to 7 percent over base in 2020 and 2050.

Sectors such as motor vehicle manufacturing that rely heavily on combustion engine inputs, see costs rise; thus their prices rise and output falls. The price of consumer transportation rises

[28] REG16(I,'CTRNS') = (SUM(J, SAM(J,'CTRNS')) + .9*4.698)/SUM(J, SAM(J,'CTRNS'));
[29] REG1('ENGIN',I) = (SUM(J,SAM('ENGIN',J)) + .1*4.698 + .125)/SUM(J,SAM('ENGIN',J));
[30] REG16(I,'CFUEL') = (SUM(J, SAM(J,'CFUEL')) - .9*9.284 )/SUM(J, SAM(J,'CFUEL'));
[31] REG1('PETRO',I) = (SUM(J,SAM('PETRO',J)) - .1*9.284)/SUM(J,SAM('PETRO',J));

**Table A-7. Comparison of Selected Results for Base Model and Scenario 2 Runs of E-DRAM in Both 2020 and 2050**

| | 2020 | | 2050 | |
|---|---|---|---|---|
| | BASE MODEL | SCNRIO2 | BASE MODEL | SCNRIO2 |
| CA OUTPUT ($BILLION) | 3078.0223 | 3070.0183 | 6568.5732 | 6553.2078 |
| % CHANGE CA OUTPUT | 0.10% | -0.26% | 0.11% | -0.23% |
| CA PERSONAL INCOME ($BILLION) | 2009.5373 | 2010.4295 | 4325.2331 | 4330.7327 |
| % CHANGE CA PERS. INC. | 0.11% | 0.04% | 0.12% | 0.13% |
| LABOR DEMAND (MILLIONS) | 18.6605 | 18.7119 | 27.9673 | 28.0539 |
| % CHNGE LABOR DEMAND | 0.03% | 0.28% | 0.04% | 0.31% |
| PRICE OF CFOOD | 1.0001 | 1.0002 | 1.0001 | 1.0000 |
| PRICE OF CHOME | 1.0000 | 1.0001 | 1.0001 | 0.9999 |
| PRICE OF CFUEL | 1.0000 | 0.9111 | 1.0000 | 0.9088 |
| PRICE OF CFURN | 1.0001 | 1.0002 | 1.0001 | 1.0000 |
| PRICE OF CCLOTH | 1.0001 | 1.0002 | 1.0001 | 1.0001 |
| PRICE OF CTRANS | 1.0000 | 1.0171 | 1.0001 | 1.0126 |
| PRICE OF CMED | 1.0001 | 1.0006 | 1.0001 | 1.0004 |
| PRICE OF CAMUS | 1.0000 | 1.0002 | 1.0001 | 1.0000 |
| PRICE OF COTHR | 1.0000 | 1.0001 | 1.0001 | 1.0000 |
| ENMIN | | | | |
| OUTPUT ($BILLION) | 6.2086 | 5.7836 | 7.6887 | 7.0685 |
| % CHANGE OUTPUT | 0.08% | -6.84% | 0.07% | -8.07% |
| IMPORTS ($BILLION) | 36.0105 | 32.6693 | 57.4093 | 50.5293 |
| % CHANGE IMPORTS | 0.07% | -9.28% | 0.08% | -11.98% |
| EXPORTS ($BILLION) | 1.0965 | 1.1419 | 2.6396 | 2.7839 |
| % CHANGE EXPORTS | -0.07% | 4.15% | -0.09% | 5.47% |
| PETRO | | | | |
| OUTPUT ($BILLION) | 39.3048 | 34.7300 | 39.2540 | 30.4067 |
| % CHANGE OUTPUT | 0.07% | -11.64% | 0.11% | -22.54% |
| IMPORTS ($BILLION) | 15.6834 | 15.3455 | 63.6368 | 61.6306 |
| % CHANGE IMPORTS | 0.01% | -2.15% | 0.02% | -3.15% |
| EXPORTS ($BILLION) | 11.9979 | 12.2159 | 19.1419 | 19.6556 |
| % CHANGE EXPORTS | -0.02% | 1.82% | -0.02% | 2.68% |
| ENGIN | | | | |
| OUTPUT ($BILLION) | 40.4675 | 40.6323 | 87.0335 | 87.2374 |
| % CHANGE OUTPUT | 0.05% | 0.41% | 0.05% | 0.23% |
| IMPORTS ($BILLION) | 9.0494 | 9.1111 | 19.4495 | 19.5371 |
| % CHANGE IMPORTS | 0.02% | 0.68% | 0.04% | 0.45% |
| EXPORTS ($BILLION) | 13.8359 | 13.7330 | 29.7408 | 29.5942 |
| % CHANGE EXPORTS | -0.03% | -0.74% | -0.05% | -0.49% |
| CHEMS | | | | |
| OUTPUT ($BILLION) | 30.2836 | 31.3101 | 64.9941 | 67.2368 |
| % CHANGE OUTPUT | 0.22% | 3.39% | 0.24% | 3.45% |
| IMPORTS ($BILLION) | 39.3028 | 39.2798 | 84.2137 | 84.1389 |
| % CHANGE IMPORTS | 0.01% | -0.06% | 0.02% | -0.09% |
| EXPORTS ($BILLION) | 2.0905 | 2.0918 | 4.6502 | 4.6547 |
| % CHANGE EXPORTS | -0.01% | 0.06% | -0.02% | 0.10% |
| FOODS | | | | |
| OUTPUT ($BILLION) | 92.9579 | 99.2793 | 200.2299 | 214.2155 |
| % CHANGE OUTPUT | 0.14% | 6.80% | 0.17% | 6.98% |
| APPAR | | | | |
| OUTPUT ($BILLION) | 25.9513 | 27.6314 | 55.8814 | 59.8357 |
| % CHANGE OUTPUT | 0.20% | 6.47% | 0.25% | 7.08% |
| MOTOR | | | | |
| OUTPUT ($BILLION) | 18.2243 | 18.0770 | 39.3478 | 39.0798 |
| % CHANGE OUTPUT | 0.23% | -0.81% | 0.24% | -0.68% |

0.17 percent and 0.13 percent in 2020 and 2050, respectively, while motor vehicle sector output falls 0.81 percent and 0.68 percent in those same times.

### A.4.3 Scenario 3: ACEE-Moderate + Fuel Cell Vehicles

Scenario 3 incorporates fuel efficiency improvements in light-duty vehicles, substantial penetration of light-duty fuel cell vehicles, and again diesel blends of GTL or FTD fuels. This scenario was constructed to level demand for gasoline and diesel fuels to 2002 levels (about 17.3 billion g.g.e). As in Scenario 2, all new LDVs starting in 2008 would have ACEEE advanced fuel economy technologies. FTD would also be blended into all diesel fuels.

Fuel cell vehicles using compressed hydrogen were then introduced to maintain and level out gasoline and diesel demand to 2002 levels. In other words, the reduction in demand from ACEEE technologies, plus the displacement of diesel from FTD blends, plus the displacement of gasoline from hydrogen fuel cells completely offsets the growth in demand from 2002 to 2050. Obviously, this is a very aggressive scenario and was selected as one of the upper bounding cases.

Table A-8 shows our estimates of the economic inputs to the modeling. Costs to households are 3 to 4 times higher than in the previous scenarios; a hydrogen industry develops; and the refining industry loses revenue to foreign suppliers of FTD (could be the same energy company), customers with more efficient gasoline vehicles, and new hydrogen industry (also could be the same energy companies).

Scenario 3 code is similar to the previous ones, but with additional lines to model hydrogen displacing gasoline.

The cost of consumer transportation (CTRNS) increases by 90 percent of projected consumer cost. These additional costs are inserted such that the new, higher amount of consumer transportation spending is expressed as the appropriate multiple of old spending.[32]

The cost of industrial engines increases by 10 percent of the projected consumer cost, plus the commercial costs. These additional costs are inserted such that the new, higher amount of industrial spending on engines is expressed as the appropriate multiple of old spending.[33]

90 percent of the projected savings from increased fuel efficiency accrue to consumers. These savings are inserted such that the new, lower amount of consumer fuel spending is expressed as the appropriate fraction of old spending.[34]

10 percent of the projected savings from increased fuel efficiency accrue to industry. These savings are inserted such that the new, lower amount of industrial spending on fuel is expressed as the appropriate multiple of old spending.[35]

[32] REG16(I,'CTRNS') = (SUM(J, SAM(J,'CTRNS')) + .9*7.193)/SUM(J, SAM(J,'CTRNS'));
[33] REG1('ENGIN',I) = (SUM(J,SAM('ENGIN',J)) + .1*7.193 + .125)/SUM(J,SAM('ENGIN',J));
[34] REG16(I,'CFUEL') = (SUM(J, SAM(J,'CFUEL')) - .9*8.269 )/SUM(J, SAM(J,'CFUEL'));

**Table A-8. Estimated Economic Inputs for Scenario 3: ACEE-Moderate + Fuel Cell Vehicles (Reducing Fuel Use to 2002 Levels)**

| Changes in Consumer Expenditures | Million 2002 $ | | Changes in Sector Revenue | Million 2002 $ | |
|---|---|---|---|---|---|
| | 2020 | 2050 | | 2020 | 2050 |
| Cost | | | Benefit | | |
| Household (inc. vehicle cost) | 5,680 | 10,463 | Vehicle Mfg. (inc. vehicle revenue) | 5,680 | 10,463 |
| Household (inc. FCV cost | 945 | 1,133 | Vehicle Mfg. (inc. FCV revenue) | 945 | 1,133 |
| Household (inc. PZEV cost) | 443 | 322 | Vehicle Mfg. (inc. PZEV revenue) | 443 | 322 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Household (inc. $H_2$ cost) | 776 | 8,718 | Hydrogen industry (inc. revenue) | 673 | 7,609 |
| | | | California Excise Tax (inc. $H_2$ revenue) | 52 | 554 |
| | | | Federal Excise Tax (inc. $H_2$ revenue) | 52 | 554 |
| Total Cost | 7,970 | 20,782 | Total Benefits | 7,970 | 20,782 |
| Benefits | | | Cost | | |
| Household (dec. gasoline expenditure | 8,269 | 26,170 | Refiners (decrease in revenue) | 6,454 | 20,425 |
| | | | California Excise Tax (dec. revenue) | 908 | 2,872 |
| | | | Federal Excise Tax (dec. revenue) | 908 | 2,872 |
| Total Benefits | 8,269 | 26,170 | Total Costs | 8,269 | 26,170 |

This scenario, unlike the others, includes expenditures on hydrogen fuel via the chemical (CHEM) sector that displaces money previously spent on the fossil fuels provided by the energy and mining (ENMIN) sector.[36]

Table A-9 compares selected results for base model and Scenario 3 runs of E-DRAM in both 2020 and 2050. Results show that Scenario 3 slightly reduces state output (by 0.28 percent in 2020 and 0.26 percent in 2050) while leaving state personal income roughly within the bounds of model calibration. *Real* personal income remains essentially constant while output falls because of increased consumer purchasing power due to improved fuel efficiency. Results indicate that the price of consumer fuel – interpreted as the price of vehicle miles traveled – is roughly 8 percent lower in 2020 and 12 percent lower 2050 under Scenario 3 than in base.

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[35] REG1('PETRO',I) = (SUM(J,SAM('PETRO',J)) - .1*8.269)/SUM(J,SAM('PETRO',J));

[36] REG1('CHEMS','PETRO') = (SAM('CHEMS','PETRO') + .776) / SAM('CHEMS','PETRO');
REG1('ENMIN','PETRO') = (SAM('ENMIN','PETRO') - .776) / SAM('ENMIN','PETRO');

**Table A-9. Comparison of Selected Results for Base Model and Scenario 3 Runs of E-DRAM in Both 2020 and 2050**

| | 2020 | | 2050 | |
|---|---|---|---|---|
| | BASE MODEL | SCNRIO3 | BASE MODEL | SCNRIO3 |
| CA OUTPUT ($BILLION) | 3078.0223 | 3069.4120 | 6568.5732 | 6551.2810 |
| % CHANGE CA OUTPUT | 0.10% | -0.28% | 0.11% | -0.26% |
| CA PERSONAL INCOME ($BILLION) | 2009.5373 | 2006.5412 | 4325.2331 | 4330.4291 |
| % CHANGE CA PERS. INC. | 0.11% | -0.15% | 0.12% | 0.12% |
| LABOR DEMAND (MILLIONS) | 18.6605 | 18.6841 | 27.9673 | 28.0763 |
| % CHNGE LABOR DEMAND | 0.03% | 0.13% | 0.04% | 0.39% |
| PRICE OF CFOOD | 1.0001 | 1.0013 | 1.0001 | 1.0013 |
| PRICE OF CHOME | 1.0000 | 1.0008 | 1.0001 | 1.0008 |
| PRICE OF CFUEL | 1.0000 | 0.9215 | 1.0000 | 0.8801 |
| PRICE OF CFURN | 1.0001 | 1.0011 | 1.0001 | 1.0011 |
| PRICE OF CCLOTH | 1.0001 | 1.0011 | 1.0001 | 1.0011 |
| PRICE OF CTRANS | 1.0000 | 1.0271 | 1.0001 | 1.0208 |
| PRICE OF CMED | 1.0001 | 1.0020 | 1.0001 | 1.0021 |
| PRICE OF CAMUS | 1.0000 | 1.0013 | 1.0001 | 1.0012 |
| PRICE OF COTHR | 1.0000 | 1.0008 | 1.0001 | 1.0008 |
| ENMIN | | | | |
| OUTPUT ($BILLION) | 6.2086 | 5.7448 | 7.6887 | 6.3197 |
| % CHANGE OUTPUT | 0.08% | -7.47% | 0.07% | -17.81% |
| IMPORTS ($BILLION) | 36.0105 | 32.5922 | 57.4093 | 43.5417 |
| % CHANGE IMPORTS | 0.07% | -9.49% | 0.08% | -24.16% |
| EXPORTS ($BILLION) | 1.0965 | 1.1430 | 2.6396 | 2.9601 |
| % CHANGE EXPORTS | -0.07% | 4.25% | -0.09% | 12.14% |
| PETRO | | | | |
| OUTPUT ($BILLION) | 39.3048 | 35.3868 | 39.2540 | 27.6640 |
| % CHANGE OUTPUT | 0.07% | -9.97% | 0.11% | -29.53% |
| IMPORTS ($BILLION) | 15.6834 | 15.3992 | 63.6368 | 61.1013 |
| % CHANGE IMPORTS | 0.01% | -1.81% | 0.02% | -3.98% |
| EXPORTS ($BILLION) | 11.9979 | 12.1807 | 19.1419 | 19.7960 |
| % CHANGE EXPORTS | -0.02% | 1.52% | -0.02% | 3.42% |
| ENGIN | | | | |
| OUTPUT ($BILLION) | 40.4675 | 40.6730 | 87.0335 | 87.1527 |
| % CHANGE OUTPUT | 0.05% | 0.51% | 0.05% | 0.14% |
| IMPORTS ($BILLION) | 9.0494 | 9.1578 | 19.4495 | 19.6373 |
| % CHANGE IMPORTS | 0.02% | 1.20% | 0.04% | 0.97% |
| EXPORTS ($BILLION) | 13.8359 | 13.6559 | 29.7408 | 29.4282 |
| % CHANGE EXPORTS | -0.03% | -1.30% | -0.05% | -1.05% |
| CHEMS | | | | |
| OUTPUT ($BILLION) | 30.2836 | 32.0653 | 64.9941 | 75.5236 |
| % CHANGE OUTPUT | 0.22% | 5.88% | 0.24% | 16.20% |
| IMPORTS ($BILLION) | 39.3028 | 39.3585 | 84.2137 | 84.3541 |
| % CHANGE IMPORTS | 0.01% | 0.14% | 0.02% | 0.17% |
| EXPORTS ($BILLION) | 2.0905 | 2.0872 | 4.6502 | 4.6417 |
| % CHANGE EXPORTS | -0.01% | -0.16% | -0.02% | -0.18% |
| FOODS | | | | |
| OUTPUT ($BILLION) | 92.9579 | 98.4497 | 200.2299 | 218.8242 |
| % CHANGE OUTPUT | 0.14% | 5.91% | 0.17% | 9.29% |
| APPAR | | | | |
| OUTPUT ($BILLION) | 25.9513 | 27.1334 | 55.8814 | 61.0011 |
| % CHANGE OUTPUT | 0.20% | 4.55% | 0.25% | 9.16% |
| MOTOR | | | | |
| OUTPUT ($BILLION) | 18.2243 | 18.0142 | 39.3478 | 38.8744 |
| % CHANGE OUTPUT | 0.23% | -1.15% | 0.24% | -1.20% |

Increased fuel efficiency reduces demand for refined petroleum products.  E-DRAM predicts petroleum sector output being 10 percent lower in 2020 and roughly 30 percent lower in 2050 under Scenario 4 versus base.  Decreased petroleum sector output – plus fuel displacement – adversely affects upstream crude oil suppliers. The model predicts energy and mining sector output being roughly 7 percent lower in 2020 and 18 percent lower in 2050 under Scenario 3 than base.

Money freed from fuel expenditure is spent in other sectors.  Scenario 3 raises food sector output by 6 and 9 percent over base in 2020 and 2050, respectively, while raising apparel sector output by roughly 5 and 9 percent over base in 2020 and 2050, respectively.

Sectors such as motor vehicle manufacturing that rely heavily on combustion engine inputs, see costs rise; thus their prices rise and output falls.  The price of consumer transportation rises 2.7 and 2.1 percent in 2020 and 2050, respectively, while motor vehicle sector output falls 1.1-1.2 percent.

### A.4.4 Scenario 4:  ACEE-Full Hybrid Vehicles

Scenario 4 is similar to 3 but even more aggressive with the introduction of all hybrid technologies starting in all light-duty vehicles in 2008.  This case is based on ACEEE — full hybrid technologies and costs.  The scenario also includes FTD blends.

Table A-10 presents our estimates of the costs and benefits for this scenario in 2002 and 2050. Here the reduction in fuel costs offset the higher vehicle costs.

**Table A-10. Estimated Economic Inputs for Scenario 4:  ACEE-Full Hybrid Vehicles**

| Changes in Consumer Expenditures | Million 2002 $ | | Changes in Sector Revenue | Million 2002 $ | |
|---|---|---|---|---|---|
| | 2020 | 2050 | | 2020 | 2050 |
| Cost | | | Benefit | | |
| Household (inc. vehicle cost) | 13,033 | 21,096 | Vehicle Mfg. (inc. vehicle revenue) | 13,033 | 21,096 |
| Household (inc. PZEV cost) | 501 | 812 | Vehicle Mfg. (inc. PZEV revenue) | 501 | 812 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Total Cost | 13,660 | 22,054 | Total Benefits | 13,660 | 22,054 |
| Benefits | | | Cost | | |
| Consumer (dec. gasoline expenditure | 12,533 | 29,896 | Refiners (decrease in revenue) | 9,782 | 23,333 |
| | | | California Excise Tax (dec. revenue) | 1,376 | 3,281 |
| | | | Federal Excise Tax (dec. revenue) | 1,376 | 3,281 |
| Total Benefits | 12,533 | 29,896 | Total Costs | 12,533 | 29,896 |

Scenario 3 code is similar to the previous ones, but with additional lines to model hydrogen displacing gasoline.

The cost of consumer transportation (CTRNS) increases by 90 percent of projected consumer cost. These additional costs are inserted such that the new, higher amount of consumer transportation spending is expressed as the appropriate multiple of old spending.[37]

The cost of industrial engines increases by 10 percent of the projected consumer cost, plus the commercial costs. These additional costs are inserted such that the new, higher amount of industrial spending on engines is expressed as the appropriate multiple of old spending.[38]

90 percent of the projected savings from increased fuel efficiency accrue to consumers. These savings are inserted such that the new, lower amount of consumer fuel spending is expressed as the appropriate fraction of old spending.[39]

10 percent of the projected savings from increased fuel efficiency accrue to industry. These savings are inserted such that the new, lower amount of industrial spending on fuel is expressed as the appropriate multiple of old spending.[40]

On a more technical note, since any model changes not overwritten from one scenario loop to the next remain in effect, fuel displacement code from Scenario 3 must be replaced with code restoring the appropriate parameters to their default settings.[41]

Table A-11 compares selected results for base model and Scenario 4 runs of E-DRAM in both 2020 and 2050. Results show that Scenario 4 slightly reduces state output (by 0.50 percent in 2020 and 0.46 percent in 2050). State personal income also falls slightly *vs.* the base cases, by 0.42 percent in 2020 and 0.16 percent in 2050. Results indicate that the price of consumer fuel – interpreted as the price of vehicle miles traveled – is roughly 12 percent lower in 2020 and 14 percent lower in 2050 under Scenario 4 than base.

Increased fuel efficiency reduces the demand for refined petroleum products. E-DRAM predicts petroleum sector output being 15 percent lower in 2020 and 33 percent lower in 2050 under Scenario 4 versus base. Decreased petroleum sector output adversely affects upstream crude oil suppliers. The model predicts energy and mining sector output being 10 percent lower in 2020 and 13 percent lower in 2050 under scenario four than base.

Money freed from fuel expenditure is spent in other sectors. Scenario 4 raises food sector output by 9 and 11 percent over base in 2020 and 2050, respectively, while raising apparel sector output by 6 and 9 percent over base in 2020 and 2050, respectively.

[37] REG16(I,'CTRNS') = (SUM(J, SAM(J,'CTRNS')) + .9*13.534)/SUM(J, SAM(J,'CTRNS'));
[38] REG1('ENGIN',I) = (SUM(J,SAM('ENGIN',J)) + .1*13.534 + .125)/SUM(J,SAM('ENGIN',J));
[39] REG16(I,'CFUEL') = (SUM(J, SAM(J,'CFUEL')) - .9*12.533 )/SUM(J, SAM(J,'CFUEL'));
[40] REG1('PETRO',I) = (SUM(J,SAM('PETRO',J)) - .1*12.533)/SUM(J,SAM('PETRO',J));
[41] REG1('PETRO',I) = (SUM(J,SAM('PETRO',J)) - .1*12.533)/SUM(J,SAM('PETRO',J));

## Table A-11. Comparison of Selected Results for Base Model and Scenario 4 Runs of E-DRAM in Both 2020 and 2050

| | 2020 | | 2050 | |
|---|---|---|---|---|
| | TODAY | SCNRIO4 | TODAY | SCNRIO4 |
| CA OUTPUT ($BILLION) | 3078.0223 | 3062.4866 | 6568.5732 | 6538.4894 |
| % CHANGE CA OUTPUT | 0.10% | -0.50% | 0.11% | -0.46% |
| CA PERSONAL INCOME ($BILLION) | 2009.5373 | 2001.0251 | 4325.2331 | 4318.1160 |
| % CHANGE CA PERS. INC. | 0.11% | -0.42% | 0.12% | -0.16% |
| LABOR DEMAND (MILLIONS) | 18.6605 | 18.6726 | 27.9673 | 28.0382 |
| % CHNGE LABOR DEMAND | 0.03% | 0.06% | 0.04% | 0.25% |
| PRICE OF CFOOD | 1.0001 | 1.0026 | 1.0001 | 1.0018 |
| PRICE OF CHOME | 1.0000 | 1.0018 | 1.0001 | 1.0012 |
| PRICE OF CFUEL | 1.0000 | 0.8818 | 1.0000 | 0.8636 |
| PRICE OF CFURN | 1.0001 | 1.0022 | 1.0001 | 1.0015 |
| PRICE OF CCLOTH | 1.0001 | 1.0023 | 1.0001 | 1.0016 |
| PRICE OF CTRANS | 1.0000 | 1.0513 | 1.0001 | 1.0382 |
| PRICE OF CMED | 1.0001 | 1.0038 | 1.0001 | 1.0029 |
| PRICE OF CAMUS | 1.0000 | 1.0027 | 1.0001 | 1.0018 |
| PRICE OF COTHR | 1.0000 | 1.0017 | 1.0001 | 1.0012 |
| ENMIN | | | | |
| OUTPUT ($BILLION) | 6.2086 | 5.6084 | 7.6887 | 6.7220 |
| % CHANGE OUTPUT | 0.08% | -9.67% | 0.07% | -12.57% |
| IMPORTS ($BILLION) | 36.0105 | 31.8337 | 57.4093 | 47.5359 |
| % CHANGE IMPORTS | 0.07% | -11.60% | 0.08% | -17.20% |
| EXPORTS ($BILLION) | 1.0965 | 1.1542 | 2.6396 | 2.8549 |
| % CHANGE EXPORTS | -0.07% | 5.27% | -0.09% | 8.16% |
| PETRO | | | | |
| OUTPUT ($BILLION) | 39.3048 | 33.5161 | 39.2540 | 26.4558 |
| % CHANGE OUTPUT | 0.07% | -14.73% | 0.11% | -32.60% |
| IMPORTS ($BILLION) | 15.6834 | 15.2814 | 63.6368 | 60.7897 |
| % CHANGE IMPORTS | 0.01% | -2.56% | 0.02% | -4.47% |
| EXPORTS ($BILLION) | 11.9979 | 12.2582 | 19.1419 | 19.8796 |
| % CHANGE EXPORTS | -0.02% | 2.17% | -0.02% | 3.85% |
| ENGIN | | | | |
| OUTPUT ($BILLION) | 40.4675 | 40.8046 | 87.0335 | 87.4671 |
| % CHANGE OUTPUT | 0.05% | 0.83% | 0.05% | 0.50% |
| IMPORTS ($BILLION) | 9.0494 | 9.2482 | 19.4495 | 19.7580 |
| % CHANGE IMPORTS | 0.02% | 2.20% | 0.04% | 1.59% |
| EXPORTS ($BILLION) | 13.8359 | 13.5091 | 29.7408 | 29.2304 |
| % CHANGE EXPORTS | -0.03% | -2.36% | -0.05% | -1.72% |
| CHEMS | | | | |
| OUTPUT ($BILLION) | 30.2836 | 31.6679 | 64.9941 | 68.3594 |
| % CHANGE OUTPUT | 0.22% | 4.57% | 0.24% | 5.18% |
| IMPORTS ($BILLION) | 39.3028 | 39.4178 | 84.2137 | 84.3420 |
| % CHANGE IMPORTS | 0.01% | 0.29% | 0.02% | 0.15% |
| EXPORTS ($BILLION) | 2.0905 | 2.0838 | 4.6502 | 4.6424 |
| % CHANGE EXPORTS | -0.01% | -0.32% | -0.02% | -0.17% |
| FOODS | | | | |
| OUTPUT ($BILLION) | 92.9579 | 101.3527 | 200.2299 | 221.4745 |
| % CHANGE OUTPUT | 0.14% | 9.03% | 0.17% | 10.61% |
| APPAR | | | | |
| OUTPUT ($BILLION) | 25.9513 | 27.5086 | 55.8814 | 60.8908 |
| % CHANGE OUTPUT | 0.20% | 6.00% | 0.25% | 8.96% |
| MOTOR | | | | |
| OUTPUT ($BILLION) | 18.2243 | 17.8553 | 39.3478 | 38.6851 |
| % CHANGE OUTPUT | 0.23% | -2.02% | 0.24% | -1.68% |

Sectors such as motor vehicle manufacturing that rely heavily on combustion engine inputs, see costs rise; thus their prices rise and output falls.  The price of consumer transportation rises roughly 5 and 4 percent in 2020 and 2050, respectively, while motor vehicle sector output falls roughly 2 and 1.7 percent in those same times.

### A.4.5 Scenario Comparisons

Comparing effects across scenarios in 2020 and 2050, as shown in Table A-12, reveals the following.  First, gains in fuel efficiency reduce the price of vehicle miles traveled.  Scenarios 1, 2, and 4 reflect progressively more fuel efficient technologies.  The scenarios implement static fuel cost saving of roughly $3.3 billion, $9.3 billion, and $12.5 billion, respectively and E-DRAM predicts the price of CFUEL falling sequentially by scenario to 97, 91, and 88 percent of its base level. Second, while gains in fuel efficiency, which translate into lower petroleum consumption and production, appear to reduce *nominal* state output by 0.1 to 0.5 percent depending on the scenario, *real* state income remains nearly constant because of aggregate price level deflation due lower fuel costs.  Real SPI falls by more than calibration error only under Scenario 4 /  2020 – the only permutation in which projected engine costs outweigh fuel savings.

None of the strategies appears to have significant negative impacts on the state economy as a whole.  The cost of building and buying more efficient engines is generally offset by their cheaper operating costs.  This said, however, adjustments in the energy related sectors are significant.   In 2020, ENMIN and PETRO sector output fall 2-10 and 4-15 percent below base, respectively, depending on the scenario.

## Table A-12. Scenario Comparisons

| 2020 | BASE MODEL | SCNRIO1 | SCNRIO2 | SCNRIO3 | SCNRIO4 |
|---|---|---|---|---|---|
| CA OUTPUT ($BILLION) | 3078.0223 | 3074.9243 | 3070.0183 | 3069.4120 | 3062.4866 |
| % CHANGE CA OUTPUT | 0.10% | -0.10% | -0.26% | -0.28% | -0.50% |
| CA PERSONAL INCOME ($BILLION) | 2009.5373 | 2009.5213 | 2010.4295 | 2006.5412 | 2001.0251 |
| % CHANGE CA PERS. INC. | 0.11% | 0.00% | 0.04% | -0.15% | -0.42% |
| LABOR DEMAND (MILLIONS) | 18.6605 | 18.6767 | 18.7119 | 18.6841 | 18.6726 |
| % CHNGE LABOR DEMAND | 0.03% | 0.09% | 0.28% | 0.13% | 0.06% |
| PRICE OF CFOOD | 1.0001 | 1.0001 | 1.0002 | 1.0013 | 1.0026 |
| PRICE OF CHOME | 1.0000 | 1.0000 | 1.0001 | 1.0008 | 1.0018 |
| PRICE OF CFUEL | 1.0000 | 0.9687 | 0.9111 | 0.9215 | 0.8818 |
| PRICE OF CFURN | 1.0001 | 1.0001 | 1.0002 | 1.0011 | 1.0022 |
| PRICE OF CCLOTH | 1.0001 | 1.0001 | 1.0002 | 1.0011 | 1.0023 |
| PRICE OF CTRANS | 1.0000 | 1.0072 | 1.0171 | 1.0271 | 1.0513 |
| PRICE OF CMED | 1.0001 | 1.0002 | 1.0006 | 1.0020 | 1.0038 |
| PRICE OF CAMUS | 1.0000 | 1.0001 | 1.0002 | 1.0013 | 1.0027 |
| PRICE OF COTHR | 1.0000 | 1.0000 | 1.0001 | 1.0008 | 1.0017 |
| ENMIN | | | | | |
| OUTPUT ($BILLION) | 6.2086 | 6.0575 | 5.7836 | 5.7448 | 5.6084 |
| % CHANGE OUTPUT | 0.08% | -2.43% | -6.84% | -7.47% | -9.67% |
| IMPORTS ($BILLION) | 36.0105 | 34.8290 | 32.6693 | 32.5922 | 31.8337 |
| % CHANGE IMPORTS | 0.07% | -3.28% | -9.28% | -9.49% | -11.60% |
| EXPORTS ($BILLION) | 1.0965 | 1.1122 | 1.1419 | 1.1430 | 1.1542 |
| % CHANGE EXPORTS | -0.07% | 1.43% | 4.15% | 4.25% | 5.27% |
| PETRO | | | | | |
| OUTPUT ($BILLION) | 39.3048 | 37.6902 | 34.7300 | 35.3868 | 33.5161 |
| % CHANGE OUTPUT | 0.07% | -4.11% | -11.64% | -9.97% | -14.73% |
| IMPORTS ($BILLION) | 15.6834 | 15.5646 | 15.3455 | 15.3992 | 15.2814 |
| % CHANGE IMPORTS | 0.01% | -0.76% | -2.15% | -1.81% | -2.56% |
| EXPORTS ($BILLION) | 11.9979 | 12.0739 | 12.2159 | 12.1807 | 12.2582 |
| % CHANGE EXPORTS | -0.02% | 0.63% | 1.82% | 1.52% | 2.17% |
| ENGIN | | | | | |
| OUTPUT ($BILLION) | 40.4675 | 40.5818 | 40.6323 | 40.6730 | 40.8046 |
| % CHANGE OUTPUT | 0.05% | 0.28% | 0.41% | 0.51% | 0.83% |
| IMPORTS ($BILLION) | 9.0494 | 9.0815 | 9.1111 | 9.1578 | 9.2482 |
| % CHANGE IMPORTS | 0.02% | 0.35% | 0.68% | 1.20% | 2.20% |
| EXPORTS ($BILLION) | 13.8359 | 13.7822 | 13.7330 | 13.6559 | 13.5091 |
| % CHANGE EXPORTS | -0.03% | -0.39% | -0.74% | -1.30% | -2.36% |
| CHEMS | | | | | |
| OUTPUT ($BILLION) | 30.2836 | 30.6482 | 31.3101 | 32.0653 | 31.6679 |
| % CHANGE OUTPUT | 0.22% | 1.20% | 3.39% | 5.88% | 4.57% |
| IMPORTS ($BILLION) | 39.3028 | 39.2943 | 39.2798 | 39.3585 | 39.4178 |
| % CHANGE IMPORTS | 0.01% | -0.02% | -0.06% | 0.14% | 0.29% |
| EXPORTS ($BILLION) | 2.0905 | 2.0910 | 2.0918 | 2.0872 | 2.0838 |
| % CHANGE EXPORTS | -0.01% | 0.02% | 0.06% | -0.16% | -0.32% |
| FOODS | | | | | |
| OUTPUT ($BILLION) | 92.9579 | 95.1127 | 99.2793 | 98.4497 | 101.3527 |
| % CHANGE OUTPUT | 0.14% | 2.32% | 6.80% | 5.91% | 9.03% |
| APPAR | | | | | |
| OUTPUT ($BILLION) | 25.9513 | 26.4969 | 27.6314 | 27.1334 | 27.5086 |
| % CHANGE OUTPUT | 0.20% | 2.10% | 6.47% | 4.55% | 6.00% |
| MOTOR | | | | | |
| OUTPUT ($BILLION) | 18.2243 | 18.1613 | 18.0770 | 18.0142 | 17.8553 |
| % CHANGE OUTPUT | 0.23% | -0.35% | -0.81% | -1.15% | -2.02% |

## Table A-12. Scenario Comparison (concluded)

| 2050 | BASE MODEL | SCNRIO1 | SCNRIO2 | SCNRIO3 | SCNRIO4 |
|---|---|---|---|---|---|
| CA OUTPUT ($BILLION) | 6568.5732 | 6557.2797 | 6553.2078 | 6551.2810 | 6538.4894 |
| % CHANGE CA OUTPUT | 0.11% | -0.17% | -0.23% | -0.26% | -0.46% |
| CA PERSONAL INCOME ($BILLION) | 4325.2331 | 4329.6794 | 4330.7327 | 4330.4291 | 4318.1160 |
| % CHANGE CA PERS. INC. | 0.12% | 0.10% | 0.13% | 0.12% | -0.16% |
| LABOR DEMAND (MILLIONS) | 27.9673 | 28.0326 | 28.0539 | 28.0763 | 28.0382 |
| % CHNGE LABOR DEMAND | 0.04% | 0.23% | 0.31% | 0.39% | 0.25% |
| PRICE OF CFOOD | 1.0001 | 1.0000 | 1.0000 | 1.0013 | 1.0018 |
| PRICE OF CHOME | 1.0001 | 0.9999 | 0.9999 | 1.0008 | 1.0012 |
| PRICE OF CFUEL | 1.0000 | 0.9324 | 0.9088 | 0.8801 | 0.8636 |
| PRICE OF CFURN | 1.0001 | 1.0000 | 1.0000 | 1.0011 | 1.0015 |
| PRICE OF CCLOTH | 1.0001 | 1.0000 | 1.0001 | 1.0011 | 1.0016 |
| PRICE OF CTRANS | 1.0001 | 1.0095 | 1.0126 | 1.0208 | 1.0382 |
| PRICE OF CMED | 1.0001 | 1.0003 | 1.0004 | 1.0021 | 1.0029 |
| PRICE OF CAMUS | 1.0001 | 0.9999 | 1.0000 | 1.0012 | 1.0018 |
| PRICE OF COTHR | 1.0001 | 0.9999 | 1.0000 | 1.0008 | 1.0012 |
| ENMIN | | | | | |
| OUTPUT ($BILLION) | 7.6887 | 7.2328 | 7.0685 | 6.3197 | 6.7220 |
| % CHANGE OUTPUT | 0.07% | -5.93% | -8.07% | -17.81% | -12.57% |
| IMPORTS ($BILLION) | 57.4093 | 52.2725 | 50.5293 | 43.5417 | 47.5359 |
| % CHANGE IMPORTS | 0.08% | -8.95% | -11.98% | -24.16% | -17.20% |
| EXPORTS ($BILLION) | 2.6396 | 2.7452 | 2.7839 | 2.9601 | 2.8549 |
| % CHANGE EXPORTS | -0.09% | 4.00% | 5.47% | 12.14% | 8.16% |
| PETRO | | | | | |
| OUTPUT ($BILLION) | 39.2540 | 32.6620 | 30.4067 | 27.6640 | 26.4558 |
| % CHANGE OUTPUT | 0.11% | -16.79% | -22.54% | -29.53% | -32.60% |
| IMPORTS ($BILLION) | 63.6368 | 62.1426 | 61.6306 | 61.1013 | 60.7897 |
| % CHANGE IMPORTS | 0.02% | -2.35% | -3.15% | -3.98% | -4.47% |
| EXPORTS ($BILLION) | 19.1419 | 19.5219 | 19.6556 | 19.7960 | 19.8796 |
| % CHANGE EXPORTS | -0.02% | 1.99% | 2.68% | 3.42% | 3.85% |
| ENGIN | | | | | |
| OUTPUT ($BILLION) | 87.0335 | 87.2217 | 87.2374 | 87.1527 | 87.4671 |
| % CHANGE OUTPUT | 0.05% | 0.22% | 0.23% | 0.14% | 0.50% |
| IMPORTS ($BILLION) | 19.4495 | 19.5153 | 19.5371 | 19.6373 | 19.7580 |
| % CHANGE IMPORTS | 0.04% | 0.34% | 0.45% | 0.97% | 1.59% |
| EXPORTS ($BILLION) | 29.7408 | 29.6307 | 29.5942 | 29.4282 | 29.2304 |
| % CHANGE EXPORTS | -0.05% | -0.37% | -0.49% | -1.05% | -1.72% |
| CHEMS | | | | | |
| OUTPUT ($BILLION) | 64.9941 | 66.6697 | 67.2368 | 75.5236 | 68.3594 |
| % CHANGE OUTPUT | 0.24% | 2.58% | 3.45% | 16.20% | 5.18% |
| IMPORTS ($BILLION) | 84.2137 | 84.1483 | 84.1389 | 84.3541 | 84.3420 |
| % CHANGE IMPORTS | 0.02% | -0.08% | -0.09% | 0.17% | 0.15% |
| EXPORTS ($BILLION) | 4.6502 | 4.6542 | 4.6547 | 4.6417 | 4.6424 |
| % CHANGE EXPORTS | -0.02% | 0.09% | 0.10% | -0.18% | -0.17% |
| FOODS | | | | | |
| OUTPUT ($BILLION) | 200.2299 | 210.4874 | 214.2155 | 218.8242 | 221.4745 |
| % CHANGE OUTPUT | 0.17% | 5.12% | 6.98% | 9.29% | 10.61% |
| APPAR | | | | | |
| OUTPUT ($BILLION) | 55.8814 | 58.7842 | 59.8357 | 61.0011 | 60.8908 |
| % CHANGE OUTPUT | 0.25% | 5.19% | 7.08% | 9.16% | 8.96% |
| MOTOR | | | | | |
| OUTPUT ($BILLION) | 39.3478 | 39.1508 | 39.0798 | 38.8744 | 38.6851 |
| % CHANGE OUTPUT | 0.24% | -0.50% | -0.68% | -1.20% | -1.68% |

## A.5 Sensitivity Analysis

Sensitivity analysis – examining the behavior of a model in response to key input changes – is a good way to assess a model's properties and bolster confidence in its results. E-DRAM's predecessor, DRAM, has undergone extensive sensitivity analysis, as documented in Berck, et al. (Summer 1996). For purposes of this project, it is useful to examine E-DRAM when parameters governing consumers' sensitivity to fuel prices, petroleum imports as a function of domestic price, and overall economic performance as a function of energy prices are changed. To this end, the following experiments are performed.

### A.5.1 Consumers' Response to Fuel Price Changes

Changing the own-price elasticity of demand CFUEL changes consumers' sensitivity to fuel price changes. More specifically, lowering this parameter to -0.77 (from its default setting of -0.2) makes consumers respond to a 1.0 percent decrease in the price of fuel price by demanding 0.77 percent (rather than 0.2 percent) more fuel. Economists describe the elasticity of -0.77 as more elastic than the elasticity of -0.2.

Table A-13 shows the results from running the 2020 version of E-DRAM, with new (versus old) elasticities listed in the gray (versus white) columns. The contrast is as expected. The more sensitive consumers are to fuel price changes, the less they cut back fuel consumption in response to increased fuel efficiency. This is because fuel efficiency gains trigger two opposing effects. One is a decreased demand for fuel since less is needed to produce the same number of vehicle miles traveled. The other is an increased demand for vehicle miles traveled because they're cheaper. It's the low-price elasticity of demand that governs the size of this second response, i.e., raising this parameter's (absolute) value means a greater increase in the quantity demanded per any given price decrease.

With more elastic of demand for CFUEL, statewide impacts of the scenarios being considered are dampened slightly. In Scenario 4, for example, state output declines by 0.2 percent rather than 0.5 percent and real personal income falls by 0.1 percent rather than 0.4 percent. With consumers buying relatively more fuel, ENMIN and PETRO sector output decline by only 4.6 percent and 7.4 percent, respectively, rather than by 9.7 percent and 14.7 percent, respectively. Demand for complimentary products thus rises relative to the base model, e.g., ENGIN sector output increases 1.3 percent rather than 0.8 percent. Relatively less spending is shifted to fuel substitutes like food and apparel, e.g., FOODS and APPPAR sector output increase by 8.3 percent (versus 9.0 percent in base) and 3.6 percent (versus 6.0 percent in base), respectively.

## Table A-13. Sensitivity Analysis — Consumer Response to Fuel Price Changes

| 2020 | BASE MODEL | SCNRIO1 | SCNRIO1 | SCNRIO2 | SCNRIO2 | SCNRIO3 | SCNRIO3 | SCNRIO4 | SCNRIO4 |
|---|---|---|---|---|---|---|---|---|---|
| CA OUTPUT ($BILLION) | 3078.022 | 3074.924 | 3076.657 | 3070.018 | 3075.484 | 3069.412 | 3074.329 | 3062.487 | 3070.572 |
| % CHANGE CA OUTPUT | 0.10% | -0.10% | -0.04% | -0.26% | -0.08% | -0.28% | -0.12% | -0.50% | -0.24% |
| CA PERS. INC. ($BIL.) | 2009.537 | 2009.521 | 2010.283 | 2010.429 | 2013.756 | 2006.541 | 2009.407 | 2001.025 | 2006.661 |
| % CHNGE CA PERS. INC. | 0.11% | 0.00% | 0.04% | 0.04% | 0.21% | -0.15% | -0.01% | -0.42% | -0.14% |
| LAB. DEMAND (MIL.) | 18.661 | 18.677 | 18.677 | 18.712 | 18.719 | 18.684 | 18.690 | 18.673 | 18.688 |
| % CHNGE LAB. DEMAND | 0.03% | 0.09% | 0.09% | 0.28% | 0.31% | 0.13% | 0.16% | 0.06% | 0.15% |
| PRICE OF CFOOD | 1.000 | 1.000 | 1.000 | 1.000 | 0.999 | 1.001 | 1.000 | 1.003 | 1.001 |
| PRICE OF CHOME | 1.000 | 1.000 | 1.000 | 1.000 | 0.999 | 1.001 | 1.000 | 1.002 | 1.001 |
| PRICE OF CFUEL | 1.000 | 0.969 | 0.969 | 0.911 | 0.911 | 0.922 | 0.922 | 0.882 | 0.882 |
| PRICE OF CFURN | 1.000 | 1.000 | 1.000 | 1.000 | 0.999 | 1.001 | 1.000 | 1.002 | 1.001 |
| PRICE OF CCLOTH | 1.000 | 1.000 | 1.000 | 1.000 | 0.999 | 1.001 | 1.000 | 1.002 | 1.001 |
| PRICE OF CTRANS | 1.000 | 1.007 | 1.007 | 1.017 | 1.016 | 1.027 | 1.026 | 1.051 | 1.050 |
| PRICE OF CMED | 1.000 | 1.000 | 1.000 | 1.001 | 0.999 | 1.002 | 1.001 | 1.004 | 1.002 |
| PRICE OF CAMUS | 1.000 | 1.000 | 1.000 | 1.000 | 0.999 | 1.001 | 1.000 | 1.003 | 1.001 |
| PRICE OF COTHR | 1.000 | 1.000 | 1.000 | 1.000 | 0.999 | 1.001 | 1.000 | 1.002 | 1.000 |
| ENMIN | | | | | | | | | |
| OUTPUT ($BILLION) | 6.209 | 6.058 | 6.134 | 5.784 | 6.008 | 5.745 | 5.945 | 5.608 | 5.921 |
| % CHANGE OUTPUT | 0.08% | -2.43% | -1.19% | -6.84% | -3.24% | -7.47% | -4.25% | -9.67% | -4.64% |
| IMPORTS ($BILLION) | 36.011 | 34.829 | 35.418 | 32.669 | 34.270 | 32.592 | 34.022 | 31.834 | 34.000 |
| % CHANGE IMPORTS | 0.07% | -3.28% | -1.65% | -9.28% | -4.83% | -9.49% | -5.52% | -11.60% | -5.58% |
| EXPORTS ($BILLION) | 1.096 | 1.112 | 1.104 | 1.142 | 1.120 | 1.143 | 1.123 | 1.154 | 1.123 |
| % CHANGE EXPORTS | -0.07% | 1.43% | 0.73% | 4.15% | 2.11% | 4.25% | 2.42% | 5.27% | 2.45% |
| PETRO | | | | | | | | | |
| OUTPUT ($BILLION) | 39.305 | 37.690 | 38.466 | 34.730 | 36.855 | 35.387 | 37.328 | 33.516 | 36.401 |
| % CHANGE OUTPUT | 0.07% | -4.11% | -2.14% | -11.64% | -6.23% | -9.97% | -5.03% | -14.73% | -7.39% |
| IMPORTS ($BILLION) | 15.683 | 15.565 | 15.597 | 15.345 | 15.431 | 15.399 | 15.476 | 15.281 | 15.394 |
| % CHANGE IMPORTS | 0.01% | -0.76% | -0.55% | -2.15% | -1.61% | -1.81% | -1.32% | -2.56% | -1.85% |
| EXPORTS ($BILLION) | 11.998 | 12.074 | 12.053 | 12.216 | 12.160 | 12.181 | 12.131 | 12.258 | 12.184 |
| % CHANGE EXPORTS | -0.02% | 0.63% | 0.46% | 1.82% | 1.35% | 1.52% | 1.11% | 2.17% | 1.55% |
| ENGIN | | | | | | | | | |
| OUTPUT ($BILLION) | 40.468 | 40.582 | 40.619 | 40.632 | 40.761 | 40.673 | 40.786 | 40.805 | 41.005 |
| % CHANGE OUTPUT | 0.05% | 0.28% | 0.37% | 0.41% | 0.72% | 0.51% | 0.79% | 0.83% | 1.33% |
| IMPORTS ($BILLION) | 9.049 | 9.081 | 9.076 | 9.111 | 9.089 | 9.158 | 9.139 | 9.248 | 9.213 |
| % CHANGE IMPORTS | 0.02% | 0.35% | 0.29% | 0.68% | 0.44% | 1.20% | 0.99% | 2.20% | 1.81% |
| EXPORTS ($BILLION) | 13.836 | 13.782 | 13.792 | 13.733 | 13.770 | 13.656 | 13.687 | 13.509 | 13.566 |
| % CHANGE EXPORTS | -0.03% | -0.39% | -0.32% | -0.74% | -0.48% | -1.30% | -1.07% | -2.36% | -1.95% |
| CHEMS | | | | | | | | | |
| OUTPUT ($BILLION) | 30.284 | 30.648 | 30.602 | 31.310 | 31.221 | 32.065 | 32.027 | 31.668 | 31.581 |
| % CHANGE OUTPUT | 0.22% | 1.20% | 1.05% | 3.39% | 3.09% | 5.88% | 5.76% | 4.57% | 4.28% |
| IMPORTS ($BILLION) | 39.303 | 39.294 | 39.278 | 39.280 | 39.219 | 39.358 | 39.307 | 39.418 | 39.321 |
| % CHANGE IMPORTS | 0.01% | -0.02% | -0.06% | -0.06% | -0.21% | 0.14% | 0.01% | 0.29% | 0.05% |
| EXPORTS ($BILLION) | 2.090 | 2.091 | 2.092 | 2.092 | 2.095 | 2.087 | 2.090 | 2.084 | 2.089 |
| % CHANGE EXPORTS | -0.01% | 0.02% | 0.07% | 0.06% | 0.23% | -0.16% | -0.01% | -0.32% | -0.05% |
| FOODS | | | | | | | | | |
| OUTPUT ($BILLION) | 92.958 | 95.113 | 94.919 | 99.279 | 98.760 | 98.450 | 97.975 | 101.353 | 100.663 |
| % CHANGE OUTPUT | 0.14% | 2.32% | 2.11% | 6.80% | 6.24% | 5.91% | 5.40% | 9.03% | 8.29% |
| APPAR | | | | | | | | | |
| OUTPUT ($BILLION) | 25.951 | 26.497 | 26.323 | 27.631 | 27.163 | 27.133 | 26.707 | 27.509 | 26.885 |
| % CHANGE OUTPUT | 0.20% | 2.10% | 1.43% | 6.47% | 4.67% | 4.55% | 2.91% | 6.00% | 3.60% |
| MOTOR | | | | | | | | | |
| OUTPUT ($BILLION) | 18.224 | 18.161 | 18.190 | 18.077 | 18.168 | 18.014 | 18.095 | 17.855 | 17.991 |
| % CHANGE OUTPUT | 0.23% | -0.35% | -0.19% | -0.81% | -0.31% | -1.15% | -0.71% | -2.02% | -1.28% |

### A.5.2 Elasticity of Imports with Respect to Domestic Price

Lowering the elasticity of imports with respect to domestic price (ETAM) makes the quantity of goods imported less sensitive to domestic price changes. Changing ETAM for the petroleum sector to 0.1 (from its default setting of 2) means that a 1.0 percent decrease in the domestic price of petroleum decreases imports of refined petroleum by 0.1 percent (rather than 2.0 percent).and from 4.0 to 1.0 for the energy and mining sector With these parameter changes, Similarly, changing ETAM for the ENMIN sector to 1 (from its default setting of 4) means that a 1 percent decrease in the domestic price of crude oil will decrease imports of crude oil by 1.0 percent (rather than 4.0 percent).

The parameter changes outlined above cause some domestic PETRO and ENMIN sector production to be being supplanted by imports, as expected. Table A-14 shows results from running the 2020 version of E-DRAM with new (*vs.* old) elasticities listed in the gray (versus white) columns. While statewide effects aren't appreciably different with these new parameter settings, adverse impacts on the ENMIN and PETRO sectors are amplified as falling demand is compounded by rising imports. This compounding is greatest in the ENMIN sector where domestic output falls 7.3 percent (versus 2.4 percent) in Scenario 1, 21.1 percent (versus 6.8 percent) in Scenario 2, 21.9 percent (versus 7.5 percent) in Scenario 3, and 27.6 percent (versus 9.7 percent) in Scenario 4.

Conversely, if the elasticities of trade were increased, or the domestic elasticity of supply were decreased, domestic output would be less sensitive to the scenarios and state output and personal income would be higher.

## Table A-14. Sensitivity Analysis — Elasticity of Imports with Respect to Domestic Price

| 2020 | BASE MODEL | SCNRIO1 | SCNRIO1 | SCNRIO2 | SCNRIO2 | SCNRIO3 | SCNRIO3 | SCNRIO4 | SCNRIO4 |
|---|---|---|---|---|---|---|---|---|---|
| CA OUTPUT ($BILLION) | 3078.022 | 3074.924 | 3074.649 | 3070.018 | 3069.005 | 3069.412 | 3068.447 | 3062.487 | 3061.123 |
| % CHANGE CA OUTPUT | 0.10% | -0.10% | -0.11% | -0.26% | -0.29% | -0.28% | -0.31% | -0.50% | -0.55% |
| CA PERS. INC. ($BIL.) | 2009.537 | 2009.521 | 2009.361 | 2010.429 | 2009.858 | 2006.541 | 2005.985 | 2001.025 | 2000.271 |
| % CHNGE CA PERS. INC. | 0.11% | 0.00% | -0.01% | 0.04% | 0.02% | -0.15% | -0.18% | -0.42% | -0.46% |
| LAB. DEMAND (MIL.) | 18.661 | 18.677 | 18.677 | 18.712 | 18.711 | 18.684 | 18.684 | 18.673 | 18.67164 |
| % CHNGE LAB. DEMAND | 0.03% | 0.09% | 0.09% | 0.28% | 0.27% | 0.13% | 0.12% | 0.06% | 0.06% |
| PRICE OF CFOOD | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.003 | 1.002197 |
| PRICE OF CHOME | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.002 | 1.001495 |
| PRICE OF CFUEL | 1.000 | 0.969 | 0.968 | 0.911 | 0.910 | 0.922 | 0.921 | 0.882 | 0.880875 |
| PRICE OF CFURN | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.002 | 1.001886 |
| PRICE OF CCLOTH | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.002 | 1.00194 |
| PRICE OF CTRANS | 1.000 | 1.007 | 1.007 | 1.017 | 1.017 | 1.027 | 1.027 | 1.051 | 1.051033 |
| PRICE OF CMED | 1.000 | 1.000 | 1.000 | 1.001 | 1.000 | 1.002 | 1.002 | 1.004 | 1.003364 |
| PRICE OF CAMUS | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.003 | 1.002307 |
| PRICE OF COTHR | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.002 | 1.001442 |
| ENMIN | | | | | | | | | |
| OUTPUT ($BILLION) | 6.209 | 6.058 | 5.754 | 5.784 | 4.897 | 5.745 | 4.849 | 5.608 | 4.494602 |
| % CHANGE OUTPUT | 0.08% | -2.43% | -7.32% | -6.84% | -21.13% | -7.47% | -21.90% | -9.67% | -27.61% |
| IMPORTS ($BILLION) | 36.011 | 34.829 | 35.060 | 32.669 | 33.336 | 32.592 | 33.298 | 31.834 | 32.67667 |
| % CHANGE IMPORTS | 0.07% | -3.28% | -2.64% | -9.28% | -7.43% | -9.49% | -7.53% | -11.60% | -9.26% |
| EXPORTS ($BILLION) | 1.096 | 1.112 | 1.146 | 1.142 | 1.245 | 1.143 | 1.247 | 1.154 | 1.286606 |
| % CHANGE EXPORTS | -0.07% | 1.43% | 4.47% | 4.15% | 13.54% | 4.25% | 13.75% | 5.27% | 17.34% |
| PETRO | | | | | | | | | |
| OUTPUT ($BILLION) | 39.305 | 37.690 | 37.608 | 34.730 | 34.466 | 35.387 | 35.173 | 33.516 | 33.19064 |
| % CHANGE OUTPUT | 0.07% | -4.11% | -4.32% | -11.64% | -12.31% | -9.97% | -10.51% | -14.73% | -15.56% |
| IMPORTS ($BILLION) | 15.683 | 15.565 | 15.673 | 15.345 | 15.659 | 15.399 | 15.662 | 15.281 | 15.6558 |
| % CHANGE IMPORTS | 0.01% | -0.76% | -0.07% | -2.15% | -0.15% | -1.81% | -0.13% | -2.56% | -0.18% |
| EXPORTS ($BILLION) | 11.998 | 12.074 | 12.100 | 12.216 | 12.277 | 12.181 | 12.238 | 12.258 | 12.32398 |
| % CHANGE EXPORTS | -0.02% | 0.63% | 0.85% | 1.82% | 2.32% | 1.52% | 2.00% | 2.17% | 2.72% |
| ENGIN | | | | | | | | | |
| OUTPUT ($BILLION) | 40.468 | 40.582 | 40.587 | 40.632 | 40.645 | 40.673 | 40.685 | 40.805 | 40.81842 |
| % CHANGE OUTPUT | 0.05% | 0.28% | 0.29% | 0.41% | 0.44% | 0.51% | 0.54% | 0.83% | 0.87% |
| IMPORTS ($BILLION) | 9.049 | 9.081 | 9.079 | 9.111 | 9.105 | 9.158 | 9.152 | 9.248 | 9.240452 |
| % CHANGE IMPORTS | 0.02% | 0.35% | 0.33% | 0.68% | 0.61% | 1.20% | 1.13% | 2.20% | 2.11% |
| EXPORTS ($BILLION) | 13.836 | 13.782 | 13.786 | 13.733 | 13.743 | 13.656 | 13.666 | 13.509 | 13.52159 |
| % CHANGE EXPORTS | -0.03% | -0.39% | -0.36% | -0.74% | -0.67% | -1.30% | -1.23% | -2.36% | -2.27% |
| CHEMS | | | | | | | | | |
| OUTPUT ($BILLION) | 30.284 | 30.648 | 30.661 | 31.310 | 31.336 | 32.065 | 32.087 | 31.668 | 31.69406 |
| % CHANGE OUTPUT | 0.22% | 1.20% | 1.25% | 3.39% | 3.48% | 5.88% | 5.96% | 4.57% | 4.66% |
| IMPORTS ($BILLION) | 39.303 | 39.294 | 39.285 | 39.280 | 39.255 | 39.358 | 39.334 | 39.418 | 39.38798 |
| % CHANGE IMPORTS | 0.01% | -0.02% | -0.05% | -0.06% | -0.12% | 0.14% | 0.08% | 0.29% | 0.22% |
| EXPORTS ($BILLION) | 2.090 | 2.091 | 2.092 | 2.092 | 2.093 | 2.087 | 2.089 | 2.084 | 2.08549 |
| % CHANGE EXPORTS | -0.01% | 0.02% | 0.05% | 0.06% | 0.13% | -0.16% | -0.09% | -0.32% | -0.24% |
| FOODS | | | | | | | | | |
| OUTPUT ($BILLION) | 92.958 | 95.113 | 95.145 | 99.279 | 99.343 | 98.450 | 98.512 | 101.353 | 101.4153 |
| % CHANGE OUTPUT | 0.14% | 2.32% | 2.35% | 6.80% | 6.87% | 5.91% | 5.98% | 9.03% | 9.10% |
| APPAR | | | | | | | | | |
| OUTPUT ($BILLION) | 25.951 | 26.497 | 26.507 | 27.631 | 27.650 | 27.133 | 27.152 | 27.509 | 27.52633 |
| % CHANGE OUTPUT | 0.20% | 2.10% | 2.14% | 6.47% | 6.55% | 4.55% | 4.63% | 6.00% | 6.07% |
| MOTOR | | | | | | | | | |
| OUTPUT ($BILLION) | 18.224 | 18.161 | 18.165 | 18.077 | 18.084 | 18.014 | 18.021 | 17.855 | 17.86203 |
| % CHANGE OUTPUT | 0.23% | -0.35% | -0.33% | -0.81% | -0.77% | -1.15% | -1.12% | -2.02% | -1.99% |

### A.5.3 Higher World Energy Prices

A primary motivation for decreasing petroleum dependency is limiting vulnerability to supply shocks that cause price spikes. Examining how E-DRAM assesses the impact of such spikes on the state economy – and predicting the extent to which the scenarios under consideration these impacts – is thus critical.

Table A-15 compares runs given 20 percent higher world ENMIN and PETRO prices (gray columns) with runs at original world prices (white columns). Comparing "NEW MODEL" to "BASE MODEL" columns shows that E-DRAM predicts 2020 California state product being roughly $21 billion (0.7 percent) lower and state personal income being $22 billion (1.1 percent) lower when both world PETRO and ENMIN prices are 20 percent higher. These higher world prices nudge the price of consumer fuel (CFUEL) up 6.2 percent, while the price of other consumer goods remain constant or fall slightly (0.1-0.2 percent).[42] Domestic output in the energy and mining sector rises nearly $2.2 billion (35 percent) while domestic output in the petroleum sector rises $1.0 billion (2.6 percent) as higher world prices drive down imports in those sectors.[43] Other sectors contract in the face of world energy price inflation, e.g., output of the FOODS and APPAR sectors falls by 5.6 and 7.2 percent, respectively.

Comparing the gray and white "SCENARIO#" columns confirms the intuition that strategies to improve fuel efficiency reap greater rewards in a world with higher energy prices. Higher world prices induce greater domestic production that offsets declines in California's ENMIN and PETRO sector production triggered by demand reduction due to efficiency gains. In Scenario 4 with high world prices (versus base model prices), for example, state output falls 0.4 percent (versus 0.5 percent) and personal income falls 0.2 percent (versus 0.4 percent); domestic ENMIN output falls 4.4 percent (versus 9.7 percent) and PETRO production falls 12.3 percent (versus 14.7 percent).

In experiments where the world price of only *refined* petroleum rises by 20 percent (e.g., if refining capacity were the pressing constraint), E-DRAM behaves in much the same way as discussed above, only to a lesser degree. As shown in Table A-16, comparing "BASE MODEL" and "NEW MODEL" columns shows that E-DRAM predicts 2020 California state product actually increasing slightly, as the rise in state ENMIN production triggered by a higher world crude oil price offsets declines in demand triggered by fuel efficiency gains. Other sectors contract in the face of world refined petroleum price inflation, e.g., output of the FOODS and APPAR sectors falls by 1.9 and 2.3 percent, respectively.

[42] The price of CFUEL rises by significantly less than 20% because the CFUEL sector also includes utilities.
[43] The domestic production as a share of imports is much lower in the ENMIN than in the PETRO sector.

## Table A-15. Sensitivity Analysis — Impact of 20-percent Higher World Energy and Mining Sector and Petroleum Sector Prices

| 2020 | BASE MODEL | NEW MODEL | SCNRIO1 | SCNRIO1 | SCNRIO2 | SCNRIO2 | SCNRIO3 | SCNRIO3 | SCNRIO4 | SCNRIO4 |
|---|---|---|---|---|---|---|---|---|---|---|
| CA OUTPUT ($BIL.) | 3078.022 | 3057.149 | 3074.924 | 3055.703 | 3070.018 | 3052.939 | 3069.412 | 3052.433 | 3062.487 | 3046.364 |
| % CHNGE OUTPUT | 0.10% | -0.58% | -0.10% | -0.05% | -0.26% | -0.14% | -0.28% | -0.15% | -0.50% | -0.35% |
| PERS. INC. ($BIL.) | 2009.537 | 1987.684 | 2009.521 | 1989.172 | 2010.429 | 1992.458 | 2006.541 | 1988.392 | 2001.025 | 1984.108 |
| % CHNGE PERS. INC. | 0.11% | -0.98% | 0.00% | 0.07% | 0.04% | 0.24% | -0.15% | 0.04% | -0.42% | -0.18% |
| JOBS (MIL.) | 18.661 | 18.536 | 18.677 | 18.558 | 18.712 | 18.605 | 18.684 | 18.577 | 18.673 | 18.571 |
| % CHNGE JOBS | 0.03% | -0.64% | 0.09% | 0.12% | 0.28% | 0.37% | 0.13% | 0.22% | 0.06% | 0.19% |
| PRICE OF CFOOD | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.003 | 1.002 |
| PRICE OF CHOME | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.000 | 1.002 | 1.001 |
| PRICE OF CFUEL | 1.000 | 1.062 | 0.969 | 1.030 | 0.911 | 0.969 | 0.922 | 0.979 | 0.882 | 0.938 |
| PRICE OF CFURN | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.002 | 1.002 |
| PRICE OF CCLOTH | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.001 | 1.001 | 1.002 | 1.002 |
| PRICE OF CTRANS | 1.000 | 1.000 | 1.007 | 1.008 | 1.017 | 1.017 | 1.027 | 1.027 | 1.051 | 1.052 |
| PRICE OF CMED | 1.000 | 0.998 | 1.000 | 0.998 | 1.001 | 0.999 | 1.002 | 1.000 | 1.004 | 1.002 |
| PRICE OF CAMUS | 1.000 | 0.999 | 1.000 | 0.999 | 1.000 | 0.999 | 1.001 | 1.000 | 1.003 | 1.002 |
| PRICE OF COTHR | 1.000 | 0.999 | 1.000 | 0.999 | 1.000 | 0.999 | 1.001 | 1.000 | 1.002 | 1.001 |
| ENMIN | | | | | | | | | | |
| OUTPUT ($BILLION) | 6.209 | 8.394 | 6.058 | 8.477 | 5.784 | 8.205 | 5.745 | 8.168 | 5.608 | 8.027 |
| % CHANGE OUTPUT | 0.08% | 35.31% | -2.43% | 0.99% | -6.84% | -2.25% | -7.47% | -2.69% | -9.67% | -4.37% |
| IMPORTS ($BILLION) | 36.011 | 34.875 | 34.829 | 33.762 | 32.669 | 31.738 | 32.592 | 31.701 | 31.834 | 30.946 |
| % CHANGE IMPORTS | 0.07% | -3.09% | -3.28% | -3.19% | -9.28% | -9.00% | -9.49% | -9.10% | -11.60% | -11.27% |
| EXPORTS ($BILLION) | 1.096 | 1.136 | 1.112 | 1.127 | 1.142 | 1.156 | 1.143 | 1.156 | 1.154 | 1.168 |
| % CHANGE EXPORTS | -0.07% | 3.51% | 1.43% | -0.82% | 4.15% | 1.75% | 4.25% | 1.79% | 5.27% | 2.81% |
| PETRO | | | | | | | | | | |
| OUTPUT ($BILLION) | 39.305 | 40.335 | 37.690 | 39.238 | 34.730 | 36.508 | 35.387 | 37.331 | 33.516 | 35.370 |
| % CHANGE OUTPUT | 0.07% | 2.69% | -4.11% | -2.72% | -11.64% | -9.49% | -9.97% | -7.45% | -14.73% | -12.31% |
| IMPORTS ($BILLION) | 15.683 | 14.222 | 15.565 | 13.711 | 15.345 | 13.519 | 15.399 | 13.468 | 15.281 | 13.459 |
| % CHANGE IMPORTS | 0.01% | -9.30% | -0.76% | -3.59% | -2.15% | -4.95% | -1.81% | -5.30% | -2.56% | -5.37% |
| EXPORTS ($BILLION) | 11.998 | 13.361 | 12.074 | 13.405 | 12.216 | 13.562 | 12.181 | 13.604 | 12.258 | 13.612 |
| % CHANGE EXPORTS | -0.02% | 11.34% | 0.63% | 0.33% | 1.82% | 1.51% | 1.52% | 1.82% | 2.17% | 1.88% |
| ENGIN | | | | | | | | | | |
| OUTPUT ($BILLION) | 40.468 | 40.443 | 40.582 | 40.563 | 40.632 | 40.643 | 40.673 | 40.674 | 40.805 | 40.828 |
| % CHANGE OUTPUT | 0.05% | -0.01% | 0.28% | 0.30% | 0.41% | 0.50% | 0.51% | 0.57% | 0.83% | 0.95% |
| IMPORTS ($BILLION) | 9.049 | 9.009 | 9.081 | 9.043 | 9.111 | 9.069 | 9.158 | 9.118 | 9.248 | 9.205 |
| % CHANGE IMPORTS | 0.02% | -0.42% | 0.35% | 0.37% | 0.68% | 0.67% | 1.20% | 1.21% | 2.20% | 2.17% |
| EXPORTS ($BILLION) | 13.836 | 13.904 | 13.782 | 13.847 | 13.733 | 13.802 | 13.656 | 13.721 | 13.509 | 13.579 |
| % CHANGE EXPORTS | -0.03% | 0.46% | -0.39% | -0.41% | -0.74% | -0.73% | -1.30% | -1.31% | -2.36% | -2.33% |
| CHEMS | | | | | | | | | | |
| OUTPUT ($BILLION) | 30.284 | 28.636 | 30.648 | 29.029 | 31.310 | 29.766 | 32.065 | 30.572 | 31.668 | 30.161 |
| % CHANGE OUTPUT | 0.22% | -5.23% | 1.20% | 1.37% | 3.39% | 3.95% | 5.88% | 6.76% | 4.57% | 5.32% |
| IMPORTS ($BILLION) | 39.303 | 39.601 | 39.294 | 39.599 | 39.280 | 39.573 | 39.358 | 39.657 | 39.418 | 39.705 |
| % CHANGE IMPORTS | 0.01% | 0.77% | -0.02% | 0.00% | -0.06% | -0.07% | 0.14% | 0.14% | 0.29% | 0.26% |
| EXPORTS ($BILLION) | 2.090 | 2.073 | 2.091 | 2.073 | 2.092 | 2.075 | 2.087 | 2.070 | 2.084 | 2.067 |
| % CHANGE EXPORTS | -0.01% | -0.84% | 0.02% | 0.00% | 0.06% | 0.08% | -0.16% | -0.16% | -0.32% | -0.29% |
| FOODS | | | | | | | | | | |
| OUTPUT ($BILLION) | 92.958 | 87.663 | 95.113 | 89.805 | 99.279 | 93.999 | 98.450 | 93.241 | 101.353 | 96.095 |
| % CHANGE OUTPUT | 0.14% | -5.56% | 2.32% | 2.44% | 6.80% | 7.23% | 5.91% | 6.36% | 9.03% | 9.62% |
| APPAR | | | | | | | | | | |
| OUTPUT ($BILLION) | 25.951 | 24.030 | 26.497 | 24.595 | 27.631 | 25.781 | 27.133 | 25.302 | 27.509 | 25.690 |
| % CHANGE OUTPUT | 0.20% | -7.22% | 2.10% | 2.35% | 6.47% | 7.28% | 4.55% | 5.29% | 6.00% | 6.91% |
| MOTOR | | | | | | | | | | |
| OUTPUT ($BILLION) | 18.224 | 17.880 | 18.161 | 17.829 | 18.077 | 17.772 | 18.014 | 17.707 | 17.855 | 17.565 |
| % CHANGE OUTPUT | 0.23% | -1.67% | -0.35% | -0.29% | -0.81% | -0.61% | -1.15% | -0.97% | -2.02% | -1.76% |

## Table A-16. Sensitivity Analysis — Impact of 20-percent Higher World Refined Petroleum Prices

| 2020 | BASE MODEL | NEW MODEL | SCNRIO1 | SCNRIO1 | SCNRIO2 | SCNRIO2 | SCNRIO3 | SCNRIO3 | SCNRIO4 | SCNRIO4 |
|---|---|---|---|---|---|---|---|---|---|---|
| CA OUTPUT ($BIL.) | 3078.022 | 3081.352 | 3074.924 | 3080.196 | 3070.018 | 3075.686 | 3069.412 | 3075.117 | 3062.487 | 3068.329 |
| % CHNGE OUTPUT | 0.10% | 0.20% | -0.10% | -0.04% | -0.26% | -0.18% | -0.28% | -0.20% | -0.50% | -0.42% |
| PERS. INC. ($BIL.) | 2009.537 | 2006.100 | 2009.521 | 2007.093 | 2010.429 | 2008.506 | 2006.541 | 2004.541 | 2001.025 | 1999.308 |
| % CHNGE PERS. INC. | 0.11% | -0.06% | 0.00% | 0.05% | 0.04% | 0.12% | -0.15% | -0.08% | -0.42% | -0.34% |
| JOBS (MIL.) | 18.661 | 18.629 | 18.677 | 18.651 | 18.712 | 18.688 | 18.684 | 18.660 | 18.673 | 18.650 |
| % CHNGE JOBS | 0.03% | -0.14% | 0.09% | 0.12% | 0.28% | 0.32% | 0.13% | 0.17% | 0.06% | 0.11% |
| PRICE OF CFOOD | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 | 1.001 | 1.002 | 1.003 | 1.003 |
| PRICE OF CHOME | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 | 1.001 | 1.001 | 1.002 | 1.002 |
| PRICE OF CFUEL | 1.000 | 1.024 | 0.969 | 0.991 | 0.911 | 0.933 | 0.922 | 0.943 | 0.882 | 0.903 |
| PRICE OF CFURN | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 | 1.001 | 1.002 | 1.002 | 1.003 |
| PRICE OF CCLOTH | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 | 1.001 | 1.002 | 1.002 | 1.003 |
| PRICE OF CTRANS | 1.000 | 1.001 | 1.007 | 1.008 | 1.017 | 1.018 | 1.027 | 1.028 | 1.051 | 1.052 |
| PRICE OF CMED | 1.000 | 1.001 | 1.000 | 1.001 | 1.001 | 1.001 | 1.002 | 1.003 | 1.004 | 1.004 |
| PRICE OF CAMUS | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 | 1.001 | 1.002 | 1.003 | 1.003 |
| PRICE OF COTHR | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 | 1.001 | 1.001 | 1.002 | 1.002 |
| ENMIN | | | | | | | | | | |
| OUTPUT ($BILLION) | 6.209 | 7.069 | 6.058 | 6.488 | 5.784 | 6.241 | 5.745 | 6.186 | 5.608 | 6.076 |
| % CHANGE OUTPUT | 0.08% | 13.95% | -2.43% | -8.22% | -6.84% | -11.71% | -7.47% | -12.48% | -9.67% | -14.05% |
| IMPORTS ($BILLION) | 36.011 | 38.931 | 34.829 | 38.768 | 32.669 | 36.595 | 32.592 | 36.388 | 31.834 | 35.749 |
| % CHANGE IMPORTS | 0.07% | 8.18% | -3.28% | -0.42% | -9.28% | -6.00% | -9.49% | -6.53% | -11.60% | -8.18% |
| EXPORTS ($BILLION) | 1.096 | 1.006 | 1.112 | 1.064 | 1.142 | 1.090 | 1.143 | 1.092 | 1.154 | 1.100 |
| % CHANGE EXPORTS | -0.07% | -8.29% | 1.43% | 5.74% | 4.15% | 8.29% | 4.25% | 8.54% | 5.27% | 9.34% |
| PETRO | | | | | | | | | | |
| OUTPUT ($BILLION) | 39.305 | 45.924 | 37.690 | 45.525 | 34.730 | 42.595 | 35.387 | 43.246 | 33.516 | 41.383 |
| % CHANGE OUTPUT | 0.07% | 16.92% | -4.11% | -0.87% | -11.64% | -7.25% | -9.97% | -5.83% | -14.73% | -9.89% |
| IMPORTS ($BILLION) | 15.683 | 12.239 | 15.565 | 11.154 | 15.345 | 11.006 | 15.399 | 11.041 | 15.281 | 10.964 |
| % CHANGE IMPORTS | 0.01% | -21.95% | -0.76% | -8.87% | -2.15% | -10.07% | -1.81% | -9.79% | -2.56% | -10.42% |
| EXPORTS ($BILLION) | 11.998 | 15.760 | 12.074 | 15.894 | 12.216 | 16.070 | 12.181 | 16.028 | 12.258 | 16.121 |
| % CHANGE EXPORTS | -0.02% | 31.34% | 0.63% | 0.85% | 1.82% | 1.96% | 1.52% | 1.70% | 2.17% | 2.29% |
| ENGIN | | | | | | | | | | |
| OUTPUT ($BILLION) | 40.468 | 40.422 | 40.582 | 40.538 | 40.632 | 40.599 | 40.673 | 40.634 | 40.805 | 40.775 |
| % CHANGE OUTPUT | 0.05% | -0.06% | 0.28% | 0.29% | 0.41% | 0.44% | 0.51% | 0.52% | 0.83% | 0.87% |
| IMPORTS ($BILLION) | 9.049 | 9.062 | 9.081 | 9.096 | 9.111 | 9.123 | 9.158 | 9.172 | 9.248 | 9.260 |
| % CHANGE IMPORTS | 0.02% | 0.16% | 0.35% | 0.37% | 0.68% | 0.67% | 1.20% | 1.21% | 2.20% | 2.18% |
| EXPORTS ($BILLION) | 13.836 | 13.815 | 13.782 | 13.759 | 13.733 | 13.713 | 13.656 | 13.633 | 13.509 | 13.490 |
| % CHANGE EXPORTS | -0.03% | -0.18% | -0.39% | -0.40% | -0.74% | -0.74% | -1.30% | -1.31% | -2.36% | -2.35% |
| CHEMS | | | | | | | | | | |
| OUTPUT ($BILLION) | 30.284 | 29.951 | 30.648 | 30.394 | 31.310 | 31.066 | 32.065 | 32.010 | 31.668 | 31.429 |
| % CHANGE OUTPUT | 0.22% | -0.88% | 1.20% | 1.48% | 3.39% | 3.72% | 5.88% | 6.88% | 4.57% | 4.93% |
| IMPORTS ($BILLION) | 39.303 | 39.408 | 39.294 | 39.393 | 39.280 | 39.375 | 39.358 | 39.460 | 39.418 | 39.512 |
| % CHANGE IMPORTS | 0.01% | 0.28% | -0.02% | -0.04% | -0.06% | -0.08% | 0.14% | 0.13% | 0.29% | 0.26% |
| EXPORTS ($BILLION) | 2.090 | 2.084 | 2.091 | 2.085 | 2.092 | 2.086 | 2.087 | 2.081 | 2.084 | 2.078 |
| % CHANGE EXPORTS | -0.01% | -0.30% | 0.02% | 0.04% | 0.06% | 0.09% | -0.16% | -0.14% | -0.32% | -0.29% |
| FOODS | | | | | | | | | | |
| OUTPUT ($BILLION) | 92.958 | 91.080 | 95.113 | 93.388 | 99.279 | 97.496 | 98.450 | 96.681 | 101.353 | 99.545 |
| % CHANGE OUTPUT | 0.14% | -1.88% | 2.32% | 2.53% | 6.80% | 7.04% | 5.91% | 6.15% | 9.03% | 9.29% |
| APPAR | | | | | | | | | | |
| OUTPUT ($BILLION) | 25.951 | 25.313 | 26.497 | 25.919 | 27.631 | 27.045 | 27.133 | 26.551 | 27.509 | 26.920 |
| % CHANGE OUTPUT | 0.20% | -2.27% | 2.10% | 2.39% | 6.47% | 6.85% | 4.55% | 4.89% | 6.00% | 6.35% |
| MOTOR | | | | | | | | | | |
| OUTPUT ($BILLION) | 18.224 | 18.151 | 18.161 | 18.103 | 18.077 | 18.024 | 18.014 | 17.959 | 17.855 | 17.805 |
| % CHANGE OUTPUT | 0.23% | -0.18% | -0.35% | -0.26% | -0.81% | -0.70% | -1.15% | -1.06% | -2.02% | -1.90% |

Comparing “SCNENARIO#” columns again indicates that strategies to improve fuel efficiency reap greater rewards when world energy prices are relatively high. With 20 percent higher world petroleum prices, declines in state output and employment due to the various scenarios are generally 20 to 50 percent less than they would be with lower world prices. The higher world PETRO prices bring forth greater domestic PETRO production, thus offsetting declines in California's PETRO, and by extension, ENMIN, sectors that demand reduction due to efficiency gains would otherwise have triggered. In Scenario 4 with high world prices (versus base model prices), for example, state output falls 0.4 percent (versus 0.5 percent) and state personal income falls 0.3 percent (versus 0.4 percent), as domestic PETRO production falls only 9.9 percent (versus 14.7 percent).

### A.5.4 Energy Tax

Another way to reduce petroleum use, and thus energy dependence, is to raise the price of petroleum. Table A-17 compares selected output for runs with an additional 20-percent state sales tax on PETRO (gray columns) with base runs (white columns) of E-DRAM.

Imposing such a tax reduces state output by 0.6 to 0.7 percent and state income by 0.4 to 0.6 percent. It increases the price of CFUEL 4.7 to 6.0 percent while reducing domestic PETRO production 4.9 to 17.0 percent and domestic ENMIN production 3.7 to 6.7 percent. Unlike fuel efficiency strategies, the tax raises the price of vehicle miles traveled and thus does not generate cost savings that can be shifted to other sectors. Output across all sectors thus contracts slightly as the tax is basically inflationary.

**Table A-17. Comparison of Selected Output for Runs with an Additional 20-percent State Sales Tax on PETRO and Base E-DRAM Runs**

| | 1999 | | 2020 | | 2050 | |
|---|---|---|---|---|---|---|
| | BASE MODEL | TAX | BASE MODEL | TAX | BASE MODEL | TAX |
| CA OUTPUT ($BIL.) | 1378.090 | 1367.183 | 3078.022 | 3057.935 | 6568.573 | 6532.449 |
| % CHNGE OUTPUT | 0.08% | -0.71% | 0.10% | -0.65% | 0.11% | -0.55% |
| PERS. INC. ($BIL.) | 892.489 | 886.188 | 2009.537 | 1998.180 | 4325.233 | 4306.451 |
| % CHNGE PERS. INC. | 0.09% | -0.62% | 0.11% | -0.57% | 0.12% | -0.43% |
| PRICE OF CFOOD | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 |
| PRICE OF CHOME | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 |
| PRICE OF CFUEL | 1.000 | 1.060 | 1.000 | 1.054 | 1.000 | 1.047 |
| PRICE OF CFURN | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 |
| PRICE OF CCLOTH | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 |
| PRICE OF CTRANS | 1.000 | 1.002 | 1.000 | 1.002 | 1.000 | 1.002 |
| PRICE OF CMED | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 |
| PRICE OF CAMUS | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 |
| PRICE OF COTHR | 1.000 | 1.001 | 1.000 | 1.001 | 1.000 | 1.001 |
| ENMIN | | | | | | |
| OUTPUT ($BILLION) | 5.879 | 5.659 | 6.209 | 5.912 | 7.689 | 7.174 |
| % CHANGE OUTPUT | 0.09% | -3.66% | 0.08% | -4.78% | 0.07% | -6.69% |
| IMPORTS ($BILLION) | 17.540 | 17.283 | 36.011 | 35.243 | 57.409 | 55.420 |
| % CHANGE IMPORTS | 0.05% | -1.42% | 0.07% | -2.13% | 0.08% | -3.47% |
| EXPORTS ($BILLION) | 0.437 | 0.445 | 1.096 | 1.123 | 2.640 | 2.744 |
| % CHANGE EXPORTS | -0.06% | 1.58% | -0.07% | 2.40% | -0.09% | 3.96% |
| PETRO | | | | | | |
| OUTPUT ($BILLION) | 24.816 | 23.594 | 39.305 | 36.471 | 39.254 | 32.592 |
| % CHANGE OUTPUT | 0.06% | -4.87% | 0.07% | -7.21% | 0.11% | -16.97% |
| IMPORTS ($BILLION) | 2.806 | 2.854 | 15.683 | 15.942 | 63.637 | 64.399 |
| % CHANGE IMPORTS | 0.01% | 1.74% | 0.01% | 1.65% | 0.02% | 1.20% |
| EXPORTS ($BILLION) | 6.475 | 6.354 | 11.998 | 11.784 | 19.142 | 18.893 |
| % CHANGE EXPORTS | -0.01% | -1.88% | -0.02% | -1.79% | -0.02% | -1.30% |
| ENGIN | | | | | | |
| OUTPUT ($BILLION) | 17.984 | 17.900 | 40.468 | 40.313 | 87.033 | 86.761 |
| % CHANGE OUTPUT | 0.06% | -0.41% | 0.05% | -0.38% | 0.05% | -0.31% |
| IMPORTS ($BILLION) | 4.028 | 4.036 | 9.049 | 9.068 | 19.450 | 19.486 |
| % CHANGE IMPORTS | 0.01% | 0.21% | 0.02% | 0.20% | 0.04% | 0.19% |
| EXPORTS ($BILLION) | 6.145 | 6.131 | 13.836 | 13.805 | 29.741 | 29.679 |
| % CHANGE EXPORTS | -0.01% | -0.23% | -0.03% | -0.22% | -0.05% | -0.21% |
| CHEMS | | | | | | |
| OUTPUT ($BILLION) | 13.479 | 12.875 | 30.284 | 29.100 | 64.994 | 62.797 |
| % CHANGE OUTPUT | 0.19% | -4.30% | 0.22% | -3.91% | 0.24% | -3.38% |
| IMPORTS ($BILLION) | 17.534 | 17.618 | 39.303 | 39.477 | 84.214 | 84.553 |
| % CHANGE IMPORTS | 0.00% | 0.48% | 0.01% | 0.44% | 0.02% | 0.40% |
| EXPORTS ($BILLION) | 0.899 | 0.894 | 2.090 | 2.080 | 4.650 | 4.630 |
| % CHANGE EXPORTS | 0.00% | -0.53% | -0.01% | -0.49% | -0.02% | -0.44% |
| FOODS | | | | | | |
| OUTPUT ($BILLION) | 41.240 | 39.120 | 92.958 | 88.711 | 200.230 | 192.362 |
| % CHANGE OUTPUT | 0.11% | -5.04% | 0.14% | -4.57% | 0.17% | -3.93% |
| APPAR | | | | | | |
| OUTPUT ($BILLION) | 11.517 | 10.757 | 25.951 | 24.451 | 55.881 | 53.134 |
| % CHANGE OUTPUT | 0.14% | -6.47% | 0.20% | -5.78% | 0.25% | -4.92% |
| MOTOR | | | | | | |
| OUTPUT ($BILLION) | 8.051 | 7.921 | 18.224 | 17.985 | 39.348 | 38.929 |
| % CHANGE OUTPUT | 0.20% | -1.42% | 0.23% | -1.31% | 0.24% | -1.07% |

### A.5.5 Pollution Tax

For comparison's sake, a Pigouvian tax levied on industries in proportion to their oxides of nitrogen ($NO_x$) emissions is briefly considered. Summary results of experiments run using the 1999 model with taxes set such that economy-wide $NO_x$ emissions are reduced by 5, 10, and 15 percent are reported below. Table A-18 indicates that achieving 5, 10, and 15 percent reductions via such a taxation scheme would cause state product to drop 0.9, 2.0, and 3.2 percent, respectively while shrinking state personal income by 0.7, 1.6, and 2.6 percent, respectively.

**Table A-18. $NO_x$ Reductions via a Pigouvian Tax**

| 1999 | BASE MODEL | 5% NOX CUT | 10% NOX CUT | 15% NOX CUT |
|---|---|---|---|---|
| CA OUTPUT ($BILLION) | 1378.0905 | 1364.4467 | 1349.8422 | 1333.2856 |
| % CHANGE CA OUTPUT | 0.08% | -0.91% | -1.97% | -3.18% |
| CA PERSONAL INCOME ($BILLION) | 892.4894 | 885.4017 | 877.4866 | 868.1903 |
| % CHANGE CA PERS. INC. | 0.09% | -0.71% | -1.59% | -2.64% |
| GENERAL FUND REVENUE ($BILLION) | 56.7748 | 60.5554 | 64.3181 | 68.2828 |

## A.6 Conclusions

The UC Berkeley team analyzed the economic impacts of four alternative strategies for reducing California's petroleum dependence. The strategies (summarized in Appendix B) were developed in a collaborative process between ARB, CEC, and TIAX. Each scenario is built around two elements: (1) reduced gasoline demand from improved light-duty vehicle fuel economy, and (2) diesel fuel displacement from gas-to-liquid (GTL) or Fischer Tropsch diesel fuels. The scenarios were constructed to try to “bound” the possible impacts to the California economy. Scenario 1 combines off-the-shelf fuel efficiency improvements in light-duty vehicles with a 33 percent blend of FTD in diesel fuel to meet ARB’s future ULSD specification. Scenarios 2 through 4 incorporate progressively aggressive and therefore more costly fuel efficiency and/or displacement options.

The analysis uses E-DRAM, a modified version of the Dynamic Revenue Analysis Model used by the California Department of Finance. The analysis concludes that the statewide economic impacts of the strategies being considered are small. This is not surprising, given that static costs estimates of the most aggressive scenario under consideration are $14.4 billion in 2020, a time when gross state product (GSP) is projected to be nearly $3.1 trillion, and $23.3 billion in 2050, when GSP is projected to be nearly $6.6 trillion. The highest static cost estimates are thus only 0.35 to 0.47 percent of projected GSP.

Results for the most modest and aggressive scenarios are summarized below as bounding cases. As indicated above, E-DRAM predicts that general equilibrium effects on state output and income are small. Predicted impacts on petroleum refining and crude oil production sectors are much larger, and should be interpreted as worst-case effects given the E-DRAM's weakness in allocating domestic demand reductions between domestic and imported products.

Scenario 1, which embodies the most modest fuel economy improvements, may cause state gross product (GSP) and state personal income (SPI) to be slightly lower than would otherwise be the case. E-DRAM predicts Scenario 1 lowering 2020 GSP by 0.10 percent – a magnitude within the bounds of model calibration error, and 2050 GSP by 0.17 percent. The scenario's predicted effect on state personal income is essentially zero in 2020 and 0.10 percent (again, a magnitude within the bounds of calibration error) in 2050. Impacts on the directly effected sectors – crude oil producers (ENMIN) and petroleum refiners (PETRO) – are significant. E-DRAM predicts ENMIN and PETRO output falling 5.9 and 16.8 percent, respectively, (Berck and Hess, Feb. 2000). Declines in these sectors, triggered by fuel efficiency gains, are offset by fuel cost savings being spent in other sectors.

Scenario 4, which embodies the most aggressive change, has a modest impact on GSP and a marginal effect on SPI. E-DRAM predicts Scenario 4 lowering 2020 GSP by roughly 0.50 percent, and 2050 GSP by 0.46 percent. The scenario's predicted effects on SPI are -0.42 percent in 2020 and –0.46 percent in 2050. As expected, the predicted impacts of this scenario on energy related sectors are large. E-DRAM predicts ENMIN output falling 9.67 percent in 2020 and 12.57 percent in 2050. PETRO output is projected to fall 14.73 percent in 2020 and 32.6 percent in 2050. Again, reduced spending in these sectors is displaced to others.

The above results are robust to the sensitivity analyses performed. The model responds as expected to changes in the own-price elasticity of consumer demand for fuel, import elasticity, and prices. Sensitivity analysis confirms intuition that the scenarios under consideration become more attractive as world energy prices rise. Higher world energy prices simultaneous raise the consumer benefits of fuel efficiency while offsetting domestic energy producer costs by favoring domestic over imported fuel products.

### A.7 References for Appendix A

Berck, et al., *Dynamic Revenue Analysis for California,* Summer, 1996.

Berck and Hess, modification of equations from DRAM to E-DRAM are discussed in *Developing a Methodology for Assessing the Economic Impacts of Large Scale Environmental Regulations.* Changes introduce parameters that facilitate running policy scenarios as some combination of price, intermediate good, and/or investment changes, Feb. 2000.

California Energy Commission (CEC 2001), *Base Case Forecast of California Transportation Energy Demand,* Staff Draft Report, December 2001, P600-01-019.

Stillwater Consultants *California Reformulated Gasoline Oxygenate Supply Options,* prepared for California Energy Commission, March 2002.

## Appendix B. Overview of Scenarios for GE Model

The general equilibrium (GE) model predicts future economic activity, based on shifts in expenditures and revenue. The implications of these changes in economic activity are based on data collected for a known year, often referred to as the model's "base" year. As a result, the GE model is calibrated for a particular base year, with any future scenarios described relative to that frame of reference.

Each scenario is built around two basic elements: (1) gasoline displacement from improved light-duty vehicle fuel economy, and (2) diesel displacement from gas-to-liquid (GTL) fuels. While each scenario is constructed based on petroleum fuel displacement, emission control devices are also considered in this analysis, consistent with ARB's PZEV regulations. The economic implications for each of these features are captured in terms of household/consumer expenditures and resulting changes in industrial/sector revenue, and entered into the model.

### B.1 Scenario Description

The four scenarios chosen for the general equilibrium model span a range of potential petroleum reductions, with Scenario 1 representing modest fuel savings and Scenario 4 the largest decreases in fuel use. The elements of each scenario are as follows:

- Scenario 1 — EEA/Duleep Fuel Economy Improvements: Captures modest fuel savings from technologies that are easiest to implement, based on cost-effectiveness and technical viability, consistent with projections provided by K.G. Duleep/EEA. Diesel displacement from GTL and PZEV costs are also included.

- Scenario 2 — ACEEE-Advanced Fuel Economy Improvements: Describes a situation with larger assumed petroleum displacements than those found in Scenario 1. Gasoline fuel savings are based on ACEEE-Advanced technology, with higher costs and fuel economy levels. Diesel displacement from GTL and PZEV costs are also included.

- Scenario 3 — ACEEE-Moderate + Fuel Cell Vehicles: Projects increased petroleum reductions from Scenario 2, based on ACEEE-Moderate technology and hydrogen Fuel Cell Vehicles (FCVs). Starting in 2020, FCV populations are chosen to maintain total light-duty gasoline use at 2002 levels. Diesel displacement from GTL and PZEV costs are also included.

- Scenario 4 — ACEEE-Full Hybrid Vehicles: Depicts largest petroleum reductions, consistent with ACEEE-Full Hybrid technology. Diesel displacement from GTL and PZEV costs are also included.

GTL fuels were included in all four scenarios because they offer significant (approximately 1 billion gallons annually beginning in 2020) petroleum reductions, at minimal cost to consumers.

The gasoline fuel consumptions for each scenario are shown in Figure B-1.

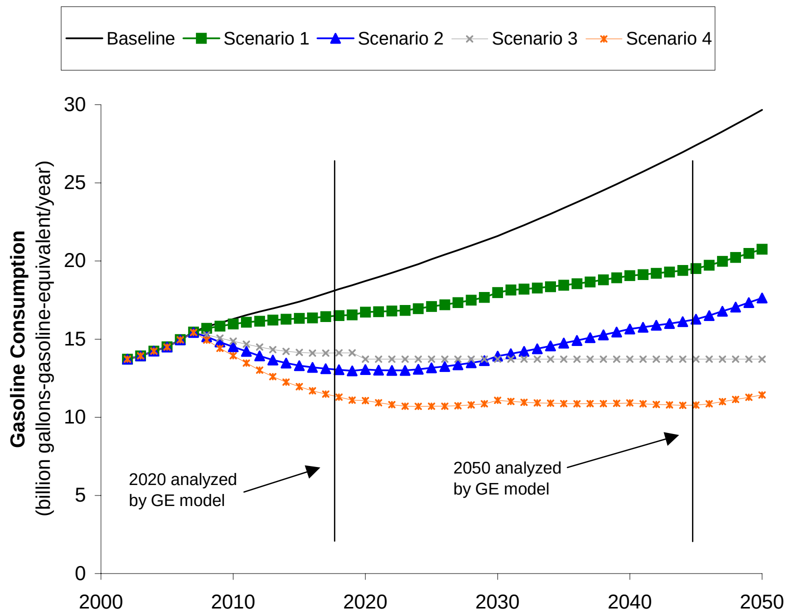



**Figure B-1. Projected Gasoline Use by Light-Duty Vehicles**

Figure B-2 shows the projected diesel fuel demand with FTD added as a blend stock. The penetration scenario is shown as a step change in 2008, which is probably unrealistic. Additional time would be required to fully introduce FTD as a blend stock to all California diesel.

Figure B-3 show the combined gasoline and diesel (expressed as gasoline-equivalent gallon) demand for the four scenarios. The scenarios shown in this figure are a combination of the gasoline and diesel results shown in Figures B-1 and B-2.

### B.2 Magnitude of Economic Impacts

The shifts in economic activities, detailed at the sector level, are shown in Tables B-1 through B-4. Just as with petroleum reduction, the scenarios span a range of economic impacts. For 2020, Scenario 1 shows a total shift of $5.351 billion ($2.087 billion costs + $3.264 billion), while Scenario 4 shows a shift of $26.193 billion ($13.660 billion costs + $12.553 billion benefits). While these impacts are large in magnitude, recall that in 2002 the California economy are approximately $1 trillion. With even a modest annual growth of 0.5 percent, the state economy would be $1.1 trillion in 2020, implying that the largest values associated with Scenario 4 would result in a total impact of no more than 2.5 percent.

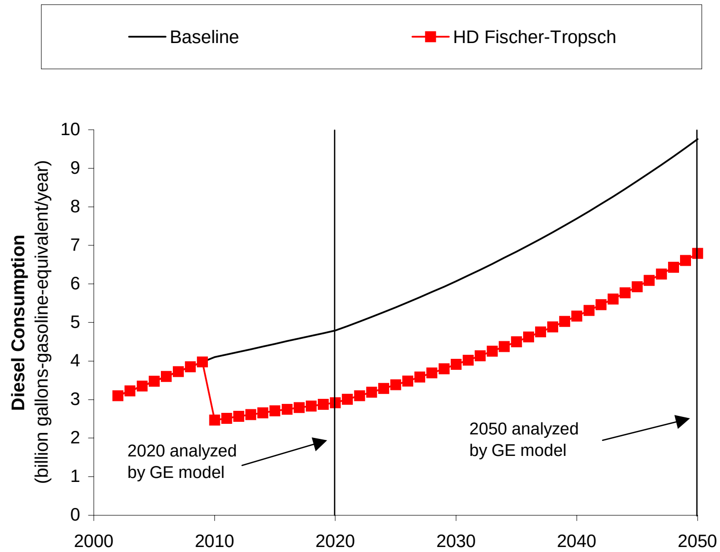



**Figure B-2. Projected Diesel Fuel Demand with FTD**

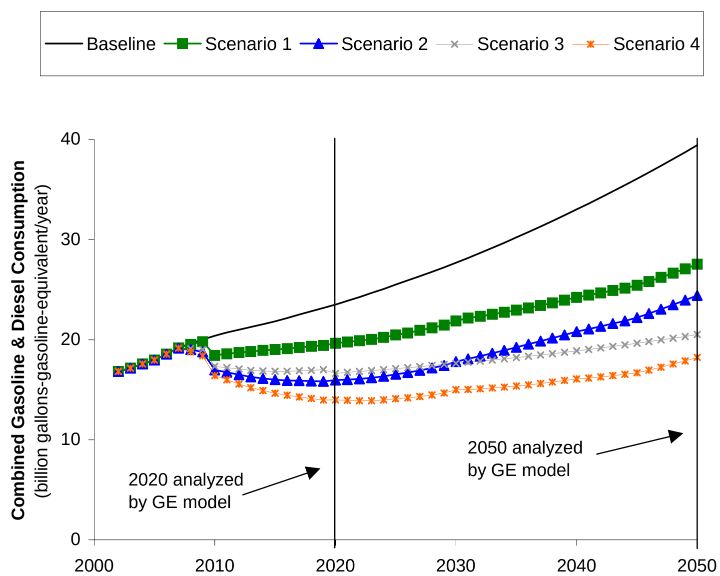



**Figure B-3. Combined Gasoline and Diesel Demand for the Four Scenarios**

## Table B-1.  Economic Impacts for Scenario 1

| Scenario 1: EEA/Duleep Fuel Economy Improvements | | | | | |
|---|---|---|---|---|---|
| Changes in Consumer Expenditures | 2020<br>million 2002$ | 2050<br>million 2002$ | Changes in Sector Revenue | 2020<br>million 2002$ | 2050<br>million 2002$ |
| Cost | | | Benefit | | |
| Household (inc. Vehicle Cost) | 1,460 | 4,900 | Vehicle Manuf. (inc. vehicle revenue) | 1,460 | 4,900 |
| Household (inc. PZEV Cost) | 501 | 812 | Vehicle Manuf. (inc. PZEV revenue) | 501 | 812 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Total Costs | 2,087 | 5,858 | Total Benefits | 2,087 | 5,858 |
| Benefit | | | Cost | | |
| Household (dec. gasoline expenditure) | 3,264 | 14,617 | Refiners (decrease in revenue) | 2,547 | 11,409 |
| | | | California Excise Tax (dec. revenue) | 358 | 1,604 |
| | | | Federal Excise Tax (dec. revenue) | 358 | 1,604 |
| Total Benefits | 3,264 | 14,617 | Total Costs | 3,264 | 14,617 |

## Table B-2.  Economic Impacts for Scenario 2

| Scenario 2: ACEEE-Advanced Fuel Economy Improvements | | | | | |
|---|---|---|---|---|---|
| Changes in Consumer Expenditures | 2020<br>million 2002$ | 2050<br>million 2002$ | Changes in Sector Revenue | 2020<br>million 2002$ | 2050<br>million 2002$ |
| Cost | | | Benefit | | |
| Household (inc. Vehicle Cost) | 4,197 | 6,794 | Vehicle Manuf. (inc. vehicle revenue) | 4,197 | 6,794 |
| Household (inc. PZEV Cost) | 501 | 812 | Vehicle Manuf. (inc. PZEV revenue) | 501 | 812 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Total Costs | 4,824 | 7,752 | Total Benefits | 4,824 | 7,752 |
| Benefit | | | Cost | | |
| Household (dec. gasoline expenditure) | 9,284 | 19,746 | Refiners (decrease in revenue) | 7,246 | 15,411 |
| | | | California Excise Tax (dec. revenue) | 1,019 | 2,167 |
| | | | Federal Excise Tax (dec. revenue) | 1,019 | 2,167 |
| Total Benefits | 9,284 | 19,746 | Total Costs | 9,284 | 19,746 |

## Table B-3.  Economic Impacts for Scenario 3

| Scenario 3: ACEEE-Moderate + Fuel Cell Vehicles (reducing fuel use to 2002 levels) | | | | | |
|---|---|---|---|---|---|
| Changes in Consumer Expenditures | 2020<br>million 2002$ | 2050<br>million 2002$ | Changes in Sector Revenue | 2020<br>million 2002$ | 2050<br>million 2002$ |
| Cost | | | Benefit | | |
| Household (inc. Vehicle Cost) | 5,680 | 10,463 | Vehicle Manuf. (inc. vehicle revenue) | 5,680 | 10,463 |
| Household (inc. FCV cost) | 945 | 1,133 | Vehicle Manuf. (inc. FCV revenue) | 945 | 1,133 |
| Household (inc. PZEV Cost) | 443 | 322 | Vehicle Manuf. (inc. PZEV revenue) | 443 | 322 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Household (inc. H2 cost) | 776 | 8,718 | Hydrogen Industry (inc. revenue) | 673 | 7,609 |
| | | | California Excise Tax (inc. H2 revenue | 52 | 554 |
| | | | Federal Excise Tax (inc. H2 revenue) | 52 | 554 |
| Total Costs | 7,970 | 20,782 | Total Benefits | 7,970 | 20,782 |
| Benefit | | | Cost | | |
| Household (dec. gasoline expenditure) | 8,269 | 26,170 | Refiners (decrease in revenue) | 6,454 | 20,425 |
| | | | California Excise Tax (dec. gas. rev) | 908 | 2,872 |
| | | | Federal Excise Tax (dec. gas. rev) | 908 | 2,872 |
| Total Benefits | 8,269 | 26,170 | Total Costs | 8,269 | 26,170 |

**Table B-4. Economic Impacts for Scenario 4**

| **Scenario 4: ACEEE-Full Hybrid Vehicles** | | | | | |
|---|---|---|---|---|---|
| Changes in Consumer Expenditures | 2020 million 2002$ | 2050 million 2002$ | Changes in Sector Revenue | 2020 million 2002$ | 2050 million 2002$ |
| Cost | | | Benefit | | |
| Consumer (inc. Vehicle Cost) | 13,033 | 21,096 | Vehicle Manuf. (inc. vehicle revenue) | 13,033 | 21,096 |
| Consumer (inc. PZEV Cost) | 501 | 812 | Vehicle Manuf. (inc. PZEV revenue) | 501 | 812 |
| Commercial (inc. GTL-diesel cost) | 125 | 146 | Foreign GTL Producer (inc. revenue) | 125 | 146 |
| Total Costs | 13,660 | 22,054 | Total Benefits | 13,660 | 22,054 |
| Benefit | | | Cost | | |
| Consumer (dec. gasoline expenditure) | 12,533 | 29,896 | Refiners (decrease in revenue) | 9,782 | 23,333 |
| | | | California Excise Tax (dec. revenue) | 1,376 | 3,281 |
| | | | Federal Excise Tax (dec. revenue) | 1,376 | 3,281 |
| Total Benefits | 12,533 | 29,896 | Total Costs | 12,533 | 29,896 |

The values given here are meant only to frame the total volume of economic activity associated with each scenario. Please note that the term "impact" is intentionally vague, implying neither "net" benefit nor penalty to the economy; this discussion only frames the input to the GE model, and its results. Whether these impacts will result in negative or positive contributions to the economy will be determined by the GE model, and described elsewhere.

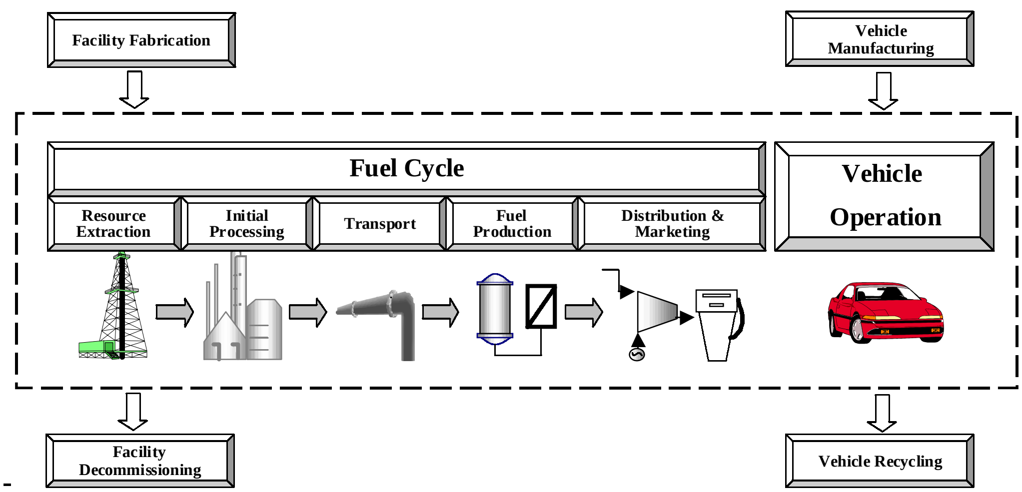
## Appendix C. Well-to-Wheel Emission Factors

### C.1 Summary

Both criteria pollutants[1] and greenhouse gases (GHG) are emitted when vehicles are operated. The emissions are also emitted during fuel production and distribution, fabrication of fuel and vehicle production facilities, decommissioning of facilities, and vehicle scrapping/recycling. These non-vehicle emissions represent a significant fraction of the total vehicle cycle both in terms of local and GHG emissions and are therefore an important consideration in assessing the environmental impacts of vehicle operation.

Figure C-1 illustrates the steps in the total vehicle energy cycle. The boundaries of the cycle can include the production and burning of the fuel as well as the production and final fate of the fuel production facilities and vehicle. Fuel cycle emissions include emissions generated during the extraction of feedstocks, processing or refining, transport, and local distribution. Vehicle cycle emissions include vehicle evaporative and tailpipe emissions.

**Figure C-1: Total Vehicle Energy Cycle**




This Appendix focuses on fuel cycle GHG and criteria pollutant emissions and vehicle GHG emissions. Vehicle criteria pollutant emissions are documented in the Main Report, Volume 3 Task. A total energy cycle analysis (TECA) would include all of these emissions. For gasoline

[1] Criteria pollutants from vehicles, discussed in Section C.2, include $NO_x$, hydrocarbons or non-methane organic gases (NMOG), CO, PM and $SO_2$.

vehicles, vehicle use represents the largest source of emissions, followed by direct fuel production emissions, with vehicle production and recycling emissions being the smallest (Wang 1999).

### C.1.1 Fuel Cycle Boundaries

Energy inputs and emissions occur throughout the fuel cycle from resource extraction through processing and transport. These emissions can occur throughout the world depending on the type of fuel and the region in the world where it is used.

This study determines fuel cycle emissions for fuels consumed in the South Coast Air Basin (SoCAB). These values are then used as a surrogate for urban area emissions throughout California. Fuel distribution logistics for the San Francisco Bay Area resemble those of the SoCAB. Stringent stationary source emission standards, fuel transport through marine terminals, and a large fraction of imported power are among the similarities. The emission estimates developed for the SoCAB are assumed for the Bay Area and other urban areas in California.

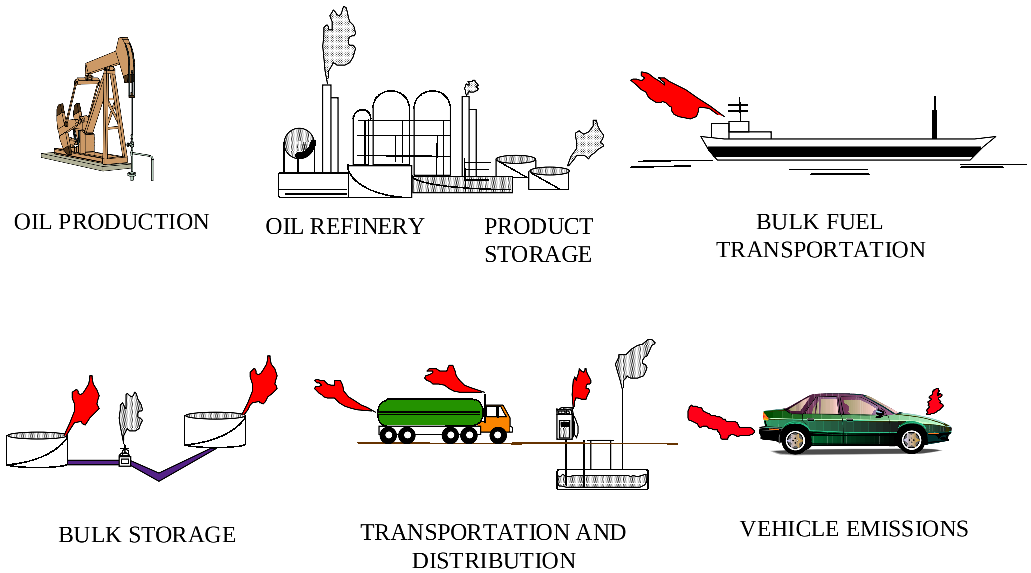
Growth projections for population and related trends in gasoline consumption indicate a larger than 30 percent increase in gasoline demand over 2002 levels by 2030. Industry experts anticipate that California refinery capacity will not increase substantially and that all of the gasoline that would be displaced by petroleum reduction strategies considered in the CEC's Task 3 report on petroleum displacement alternatives (CEC 2002) would be imported (Unnasch 1996, 2001). Because of these constraints, the analysis in this study pertains to imported gasoline, diesel, and most other fuels. For liquid fuels, the emissions in urban areas in California consist mostly of exhaust from marine vessels and tanker trucks as well as hydrocarbon losses from fuel distribution. Figure C-2 illustrates the principal steps involved in transporting liquid fuels to California, with darker shading indicating local emissions in California. Tanker ship emissions are counted for 26 nautical miles (kn) of travel (Pera). The pathways for delivering liquid fuels are similar, with the primary differences in local emissions resulting from the fuels vapor pressure and related fuel transfer emissions.

For gaseous fuels, urban emissions are associated with pipeline transport, power plants, liquefiers, and hydrogen reformers. Significant quantities of electric power are also required for gaseous fuel compression and cryogenic fuel liquefaction. Electric power provides all of the energy inputs for battery EVs and hydrogen from electrolysis. The local emission values include those associated with natural gas fired power plants and gas pipeline transport in the SoCAB.

### C.1.2 Fuel Cycle Emission Results

The results of this study include "well to wheel" (WTW) energy and GHG emissions and "well-to-tank" (WTT) criteria pollutants. Vehicle tank-to-wheel (TTW) criteria pollutant emissions vary with vehicle type, emission control requirements, and other parameters. Assumptions related to vehicle criteria pollutant emissions are presented in the Main Report, Volume 3, Task 1.

**Figure C-2: Fuel-Cycle and Vehicle Emission Sources**



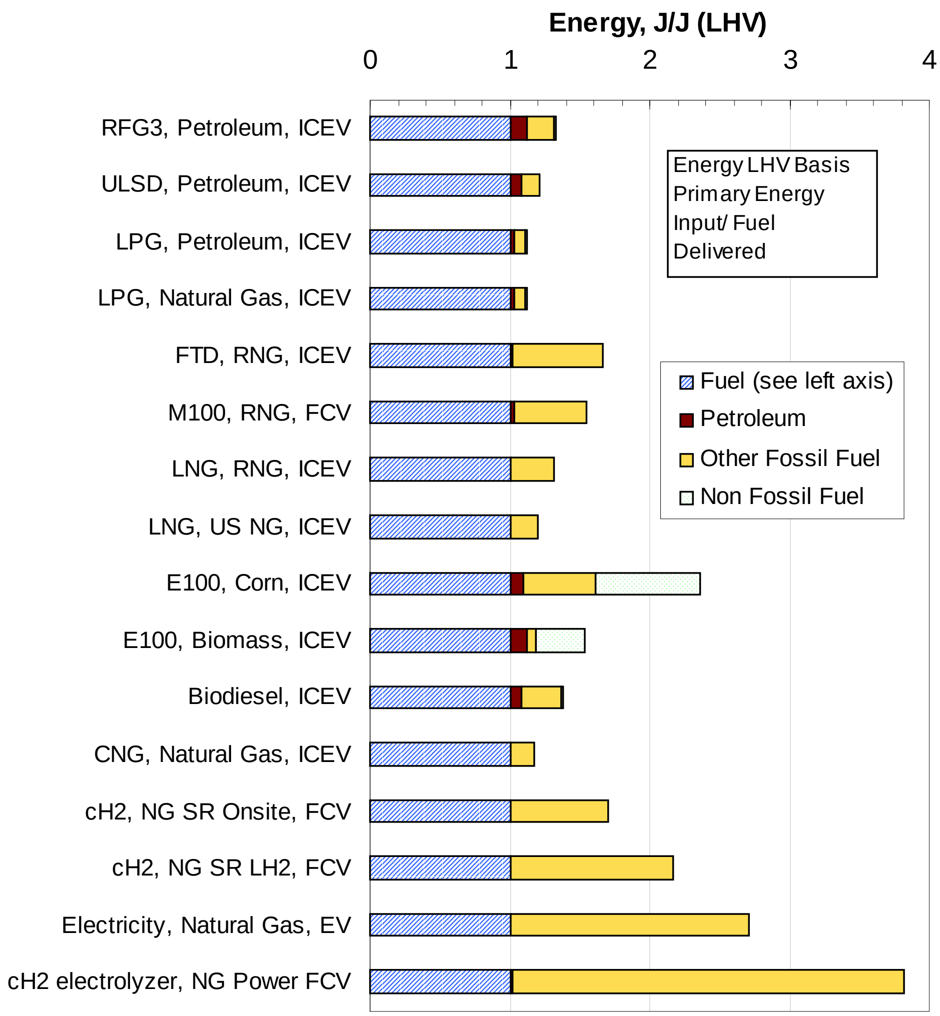

Vehicle WTW energy and GHG emissions and local WTT criteria pollutants are presented per unit fuel[2]. The full fuel cycle emissions per J of fuel do not take into account vehicle efficiency but still reflect all of the GHG emissions. In order to eliminate confusion and expectations for vehicle comparisons per mile driven, the terms WTW, WTT, and TTW are used to describe the steps or results. The fuel production and distribution emissions are referred to as fuel cycle and the vehicle emissions are referred to as vehicle cycle.

#### C.1.2.1 Summary of Energy Inputs

Fuel cycle emissions include the full chain of fuel production emissions associated with producing finished fuels. A key factor in determining the energy inputs and related emissions is the type of feedstock (oil, natural gas, coal, etc.), as the resource mix affects the fuel cycle emissions associated with producing each feedstock. Figure C-3 illustrates total energy required per unit energy delivered to the vehicle tank for the fuels considered in this study. The energy resource mix (petroleum, other fossil fuel, or non-fossil fuel) is also illustrated for the fuel cycle. These energy inputs represent the full fuel cycle, including second order effects such as the additional fuel required for producing or transporting a feedstock or fuel. The total energy includes inputs to make up for spills and other losses. The composition of fuels determines the vehicle cycle $CO_2$ emissions, as most of the carbon in the fuel is burned to form $CO_2$.

[2] Per J of energy on a lower heating value basis (LHV) or per unit of fuel for standard units of commerce (gallon of liquid fuel, kg of hydrogen, 100scf natural gas).

**Figure C-3: Fuel Cycle and Vehicle Energy Inputs**




Source: Modified GREET 1.6, California long-term assumptions in this report. Non fossil energy in the fuel cycle is primarily biomass. Results for fuel blends such as E85 can be obtained by averaging the results from two blending components, weighted by the energy fraction of each blending component.

The total length of the bars in Figure C-3 represents the inverse of fuel production efficiency. For example, for FTD from remote natural gas, the WTW energy input is 1.71 J/J fuel which corresponds to a WTW efficiency of 58.6 percent.

The values in Figure C-3 are expressed per unit energy and not on a per mile basis, which would depend on vehicle fuel consumption. A comparison of vehicle and fuel cycle energy consumption on a per mile or km basis can be obtained by multiplying the J/J values by fuel consumption.[3]

Figure C-3 summarizes single component fuels (not blended) which illustrate the energy impacts of each feedstock to fuel pathway. A variety of blended fuel combinations are considered in the Task 1 main report (for example E85, a mixture of ethanol and gasoline). The fuel cycle energy results for blended fuels are equivalent to the energy-weighted average of the individual fuel components (79.1 percent ethanol for E85, see Section C.3.4). The results for the blended fuel combinations are presented later in this report.

#### C.1.2.2 Summary of GHG Emissions

Figure C-4 illustrates total GHG emissions per unit energy delivered to the vehicle tank for the fuel considered in this study[4]. Again, the fuel and vehicle cycle values are shown separately.

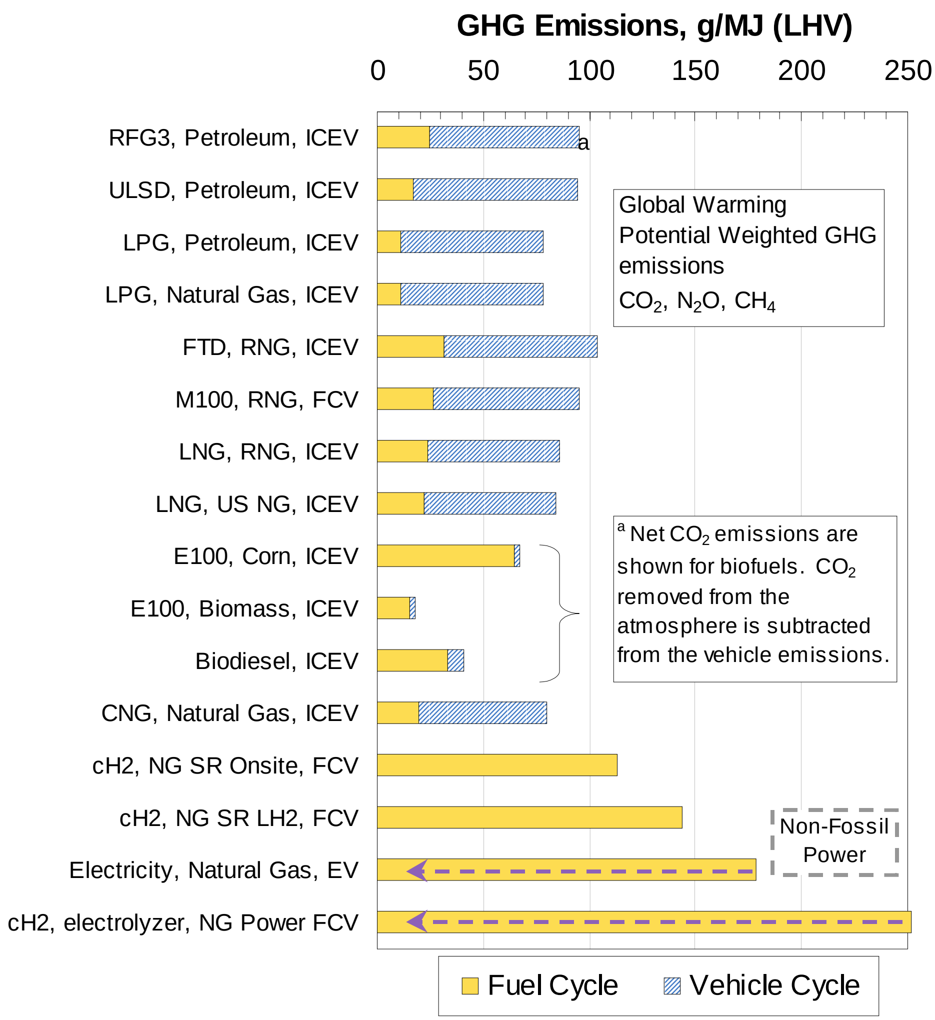
Fuel cycle GHG emissions were determined using the GREET 1.6 model, with assumptions that represent future alternative fuels used in California as well as the gasoline that would be displaced. GHG emissions include $CO_2$ as well as methane ($CH_4$) and nitrous oxide ($N_2O$), weighted for their lifetime warming potential. Scenarios for fuel production were based on similar distribution modes (tanker ship capacity, storage tank size). The different fuel cycle values reflect the energy input requirements for fuel production and distribution. $CO_2$ emissions were calculated directly from the carbon content of the fuel after accounting for fuel that is converted to CO, $CH_4$ and evaporative emissions[5]. These values are affected by the resource mix, which affects $CO_2$ emissions. $CH_4$ and $N_2O$ emissions are also included in the fuel cycle GHG emissions. These include emissions from fuel combustion as well as $CH_4$ losses from natural gas distribution. Other sources of GHG emissions include $N_2O$ from agricultural activities and $N_2O$ from corona discharge from power lines (Delucchi 1993).

[3] The comparison per mile will differ considerably among similar vehicles. For example the energy consumption for a hydrogen fuel cell vehicle could be about half that of a conventional gasoline ICEV, so the combined vehicle and fuel cycle emissions will be half that of a gasoline ICEV.

[4] Some readers take issue with applying the term WTW or TTW to the GHG emissions on an energy basis. However, these values do represent the total GHG emissions from fuel production and vehicle use. A small uncertainty is introduced with this approach. Different vehicle classes may emit different levels of $N_2O$ and $CH_4$ per MJ. These values are often estimated as constant per mile for light-duty vehicles, which is no more accurate than the approach taken here. This method of presentation facilitates calculating GHG emissions from aggregate fuel use. In order to determine GHG emissions per mile, multiply by fuel consumption in MJ/mi.

[5] This small amount of carbon conversion to pollutants other than $CO_2$ has a very small impact on the results.

**Figure C-4: Fuel Cycle and Vehicle GHG Emissions ($CO_2$ Equivalent)**




Source: Modified GREET1.6, California long-term assumptions in this report.

Vehicle emissions include $CO_2$ from fuel combustion as well as GWP weighted $CH_4$ and $N_2O$ emissions. $CO_2$ emissions relate directly to the amount of fuel burned while $CH_4$ and $N_2O$ emissions are not always directly proportional to fuel consumption. $CO_2$ emissions were calculated from the carbon content of the fuel while $CH_4$ and $N_2O$ emissions were estimated from vehicle emissions data.[6]

The fuel cycle GHG results for blended fuels are equivalent to the weighted average of the individual fuel components. The fuel cycle energy inputs for the specific blended fuel combinations are presented later in this report.

Criteria pollutant and air toxic emissions were also calculated for various fuel production pathways. These pollutants include hydrocarbons, oxides of nitrogen ($NO_x$), particulate matter (PM), sulfur dioxide ($SO_2$), and carbon monoxide (CO). Hydrocarbons are reported as non-methane organic gases (NMOG) which includes aldehydes, alcohols, and other organic components. NMOG is a pollutant category that applies to vehicle standards in California. For liquid fuel distribution, $SO_2$ is emitted from fuel combustion in marine vessels. For gaseous fuels and electric power, $SO_2$ is emitted from pipeline engines and power plants. Toxic pollutants associated with local fuel distribution were also determined.[7]

This study focuses on determining emissions in urban areas in California. The steps associated with the transportation, storage, blending, and vehicle filling are individually calculated for each fuel.[8]

Figure C-5 illustrates local fuel cycle NMOG and $NO_x$ emissions in urban areas. The pollutants are shown as stacked bars because they are both ozone precursors, although the relative contribution of each pollutant to ozone depends on background and meteorological conditions.

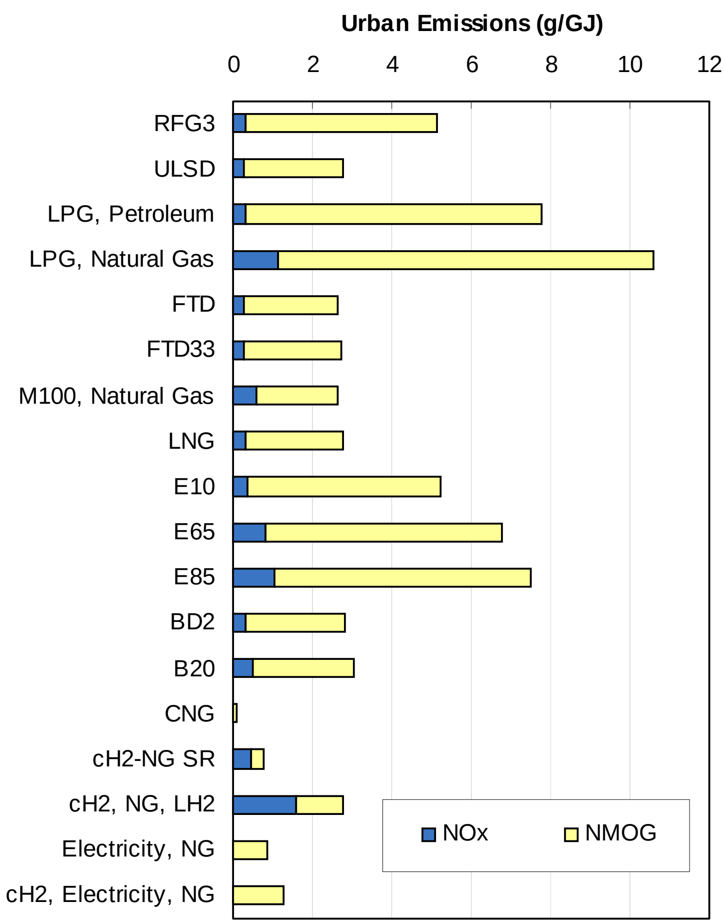
The local emissions depend largely on the conditions affecting fuel delivery to California and related study assumptions. Since all of the fuels except for hydrogen, electricity, and LNG from pressure letdown facilities are imported to California, the emissions from fuel production facilities are not counted in the SoCAB. Therefore the emissions for liquid fuel correspond to combustion emissions from tanker ships and delivery trucks and NMOG from fuel distribution. For liquid fuels, NMOG emissions correspond primarily to spills and evaporative losses associated with fuel transfers.

[6] $CH_4$ and $N_2O$ emissions were estimated to be proportional to fuel consumption. While hydrocarbon emissions are controlled and therefore typically assumed to be constant on a per mile basis, methane and $N_2O$ emissions are not. Emissions data indicate that estimating these pollutants proportional to fuel consumption is somewhat more accurate than assuming these pollutants are constant per mile.

[7] Refer to ARB listed toxic air contaminants. Those associated with fuel production include benzene, 1-3, butadiene, formaldehyde, and acetaldehyde.

[8] The molecular weight and vapor density of fuel blends do not vary in a linear fashion with blends like M85. Therefore, estimating the emissions from vapor transfer for each product represents a more accurate estimate of fuel transfer emissions. The effect on product losses and corresponding GHG emissions is trivial (See alsoWang 1994, Appendix C).

**Figure C-5: Urban California Fuel Cycle $NO_x$ and NMOG Emissions**




Source: Fuel cycle analysis for. $NO_x$ emissions from electric power generation in the SoCAB are capped by the RECLAIM program and are not included in here. These emissions would need to be offset or otherwise eliminated. Long-term emission control assumptions for LPG and LNG include enhanced vapor controls.

For gaseous fuels and electric power, the emissions correspond to power plant emissions and compressor engines for pipeline distribution.[9]

Emissions from electric power generation have been the subject of considerable analysis and debate. Electric power primarily contributes to EV charging, electrolytic hydrogen production, CNG and hydrogen compression, and cryogenic fuel liquefaction[10]. Emissions associated with operating electric fuel pumps are included in the analysis but represent an insignificant contribution to total emissions. Emissions associated with lighting and operating fueling stations are considered outside the fuel cycle and are not analyzed here.

The attribution of emissions from electric power generation to urban areas depends on the amount of power generated in the SoCAB as well as regulatory constraints on power generation facilities. The assumption for power production in the SoCAB was 40 percent based on various studies performed by the CEC and published in ARB reports (Unnasch 2001). Another constraint on power production is the requirement to offset emissions from new power plants and to limit total $NO_x$ emissions in the SoCAB. The RECLAIM program (SCAQMD 1997) places a cap on $NO_x$ emissions from power generation in the SoCAB. This program requires power generators to install more emission controls or to purchase offsets in order to achieve an overall cap on $NO_x$ emissions. In this study, $NO_x$ emissions are not attributed to power plants in the SoCAB. This approach has been extensively reviewed by a variety of energy industry and state regulator stakeholders over the years (Unnasch 2001, 1996). The emissions that would need to be offset from power plants are discussed later in this report.

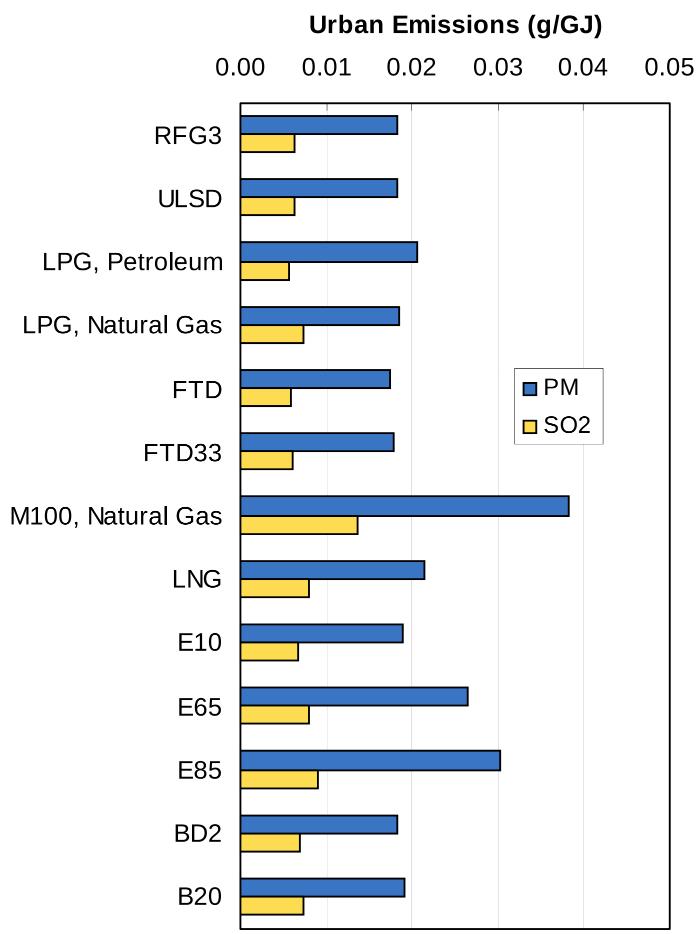
Figures C-6 and C-7 show PM and $SO_2$ emissions from within the SoCAB. For liquid fuels, these correspond primarily to emissions from marine vessel operation. These emissions were counted for operation within 26 kn of California as well as for port activities, which is consistent with the treatment of marine vessel emissions in the SCAQMD inventory (SCAQMD 1997). Some fuels would also be transported by railcar. Longer railcar distances (70 mi) were estimated in the SoCAB because of the routes that railcars would follow to import fuels from outside California. Local tanker truck emissions also contribute to PM; however, due to ARB's emission standards for heavy-duty trucks, these emissions represent a relatively small fraction of the total.

The energy density and cargo carrying capacity of various fuels affects the fuel cycle emissions and is evident when they are compared on a g/GJ basis. The effect of the fuel's energy density is illustrated when comparing FTD with M100. The emissions per gallon of fuel are similar where the energy density of M100 is about half that of FTD.

[9] Local emissions in this study are estimated to be those from marginal fuel production. Key assumptions in the analysis of marginal emissions are that gasoline and diesel are imported to California. Assumptions that affect gaseous fuels and electric vehicles.

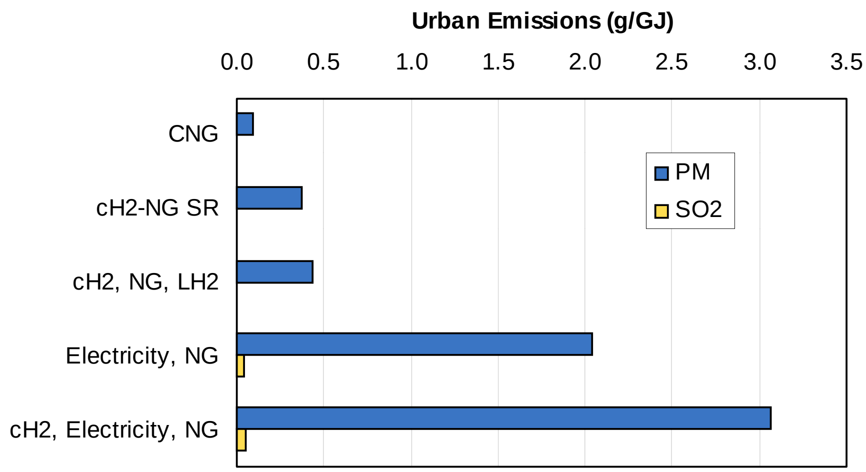
[10] Even though some refineries may import electric power, the assumption for this study is that the liquid fuels are imported on the margin, and power consumption from refineries is not counted towards urban emissions in the SoCAB).

**Figure C-6: Urban California PM and $SO_2$ Emissions for Liquid Fuels**




Source: Fuel cycle analysis for SoCAB, long-term assumptions 2,500 ppm S marine bunker fuel, 10 ppm sulfur ULSD for delivery trucks.

**Figure C-7: Urban Fuel Cycle PM and $SO_2$ Emissions for CNG, Hydrogen, and Electricity**



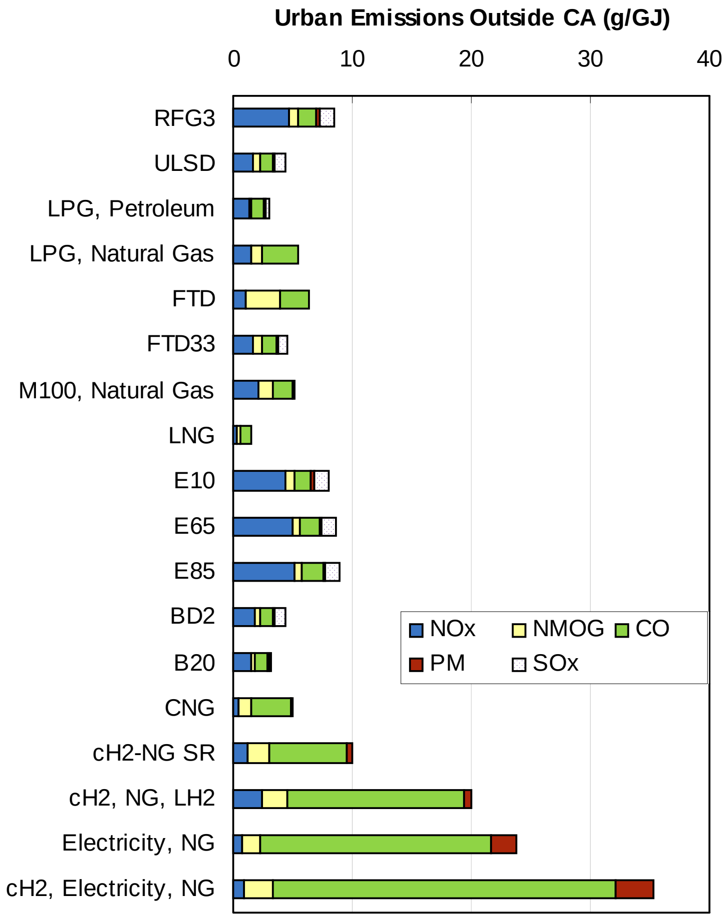

Source: Fuel cycle analysis for the SoCAB, 40% power generation in SoCAB, 30% in CA.

This study focuses on emissions in urban areas in California, with the basis for calculation being fuel distribution in the SoCAB. The resource limitations and constraints on fuel supplies for California result in the assumption that most of the finished fuels or natural gas feedstocks will be imported to California. Therefore, most fuel production emissions will occur outside the state. The emissions of criteria pollutants outside of California, in urban areas are shown in Figure C-8.

Baseline estimates in the GREET model provide the calculations for criteria pollutant emissions outside of California. These calculations take into account emission rates from production facilities, processing and transport equipment. These values from the GREET model, with the assumptions presented in this study are indicated in Figure C-8. Urban emissions estimates in GREET take into account assumptions the proximity of fuel production facilities to urban areas[11].

[11] GHG emissions are counted on a global basis irrespective of location.

**Figure C-8: Urban Criteria Pollutant Emissions Outside California**




Source: Modified GREET 1.6, California long-term assumptions in this report.

### C.1.3 Discussion of Well-to-Wheel Assumptions and Results

The circumstances related to California's potential fuel supplies combined with the study assumptions affect the fuel cycle and vehicle GHG and criteria pollutant emissions. Key factors affecting criteria pollutant emissions include the following:

- Analysis was based on imported gasoline production, so emissions in California were attributed to gasoline. Overseas refinery GHG emissions are counted towards total GHG emissions.
- In California, liquid fuel storage and distribution facilities must comply with stringent ARB and local AQMD requirements.

- Tanker ship emissions were counted for 26 kn.
- Fuel delivery trucks were assumed to comply with stringent 2007 ARB emission standards that reduce $NO_x$ and PM emissions to 10 percent of 2002 levels.
- Alternative fuels were assumed to be produced in large volumes with mature technologies and corresponding fuel efficiencies.
- Liquid fuels were assumed to be imported on 150,000 DWT tankers, which are more fuel efficient per ton-mile of fuel than smaller tankers.
- Enhanced emission control strategies were assumed for LPG and LNG infrastructure, which today have substantial venting emissions.
- Electricity for EVs and power production was based on natural gas for marginal power production (Unnasch 2001).

## C.2 Introduction

### C.2.1 Purpose of Fuel Cycle Analysis

This Appendix provides documentation of the fuel cycle analysis used in the evaluation the "Benefits of Reducing Demand for Gasoline and Diesel". For the petroleum dependency study, air emissions are counted as one of the many impacts of vehicle operation and fuel consumption. Since the petroleum dependency study calculates fuel displacement on a total statewide basis, the results presented here are per unit fuel rather than per mile.

Total fuel cycle emissions have been used to support the analysis of energy use and vehicle impacts, including the following:

- Benefits of Reducing Demand for Gasoline and Diesel, Task 1 Main Report
- Comparison of fuel cell and other vehicle options (Knight, Wang 1999, Delucchi 1993, Unnasch 1989, Weiss, GM, LBST, Thomas)
- Develop R&D Goals for Technology Development (Lasher 2002)
- Evaluate energy efficiency of vehicle options (Unnasch 2000, EPRI 2001)
- Compare fuel cycle emissions with ARB PZEV requirements (ARB 2000, Unnasch 2001)
- Emission factors for a GHG registry (WRI)

Most of these analyses aim to compare the sum of vehicle and fuel cycle emissions on a per mile driven basis. Some also include discussions of the emissions associated with material processing. A comparison of various fuel cycle studies is presented in Section C.9. The primary purpose of this study was to develop emission factors that reflect the analysis of petroleum displacement in California.

### C.2.2 Scope of Analysis

Table C-1 shows the fuel and feedstock combinations analyzed in this study. Most of the fuel/feedstock chains were inputs to the Petroleum Dependency Task 1. As the fuel cycle analysis evolved in support of other CEC studies, the results for additional fuel pathways are also presented here. The fuel combinations are grouped according to the following:

**Table C-1: Fuel and Feedstock Combinations**

| Fuel | Feedstock, Source |
|---|---|
| Liquid Fuels | |
| ULSD | Overseas refinery, petroleum |
| LPG from Petroleum | CA refinery, petroleum |
| LPG from NG | Natural gas processing plant |
| M100 | Remote natural gas |
| FTD | Remote natural gas |
| LNG | Remote natural gas |
| LNG | U.S. natural gas facilities[a] |
| Blending Components | |
| CARBOB | Overseas refinery |
| Biodiesel | Rapeseed oil |
| E100 corn | Midwest corn |
| E100 biomass | Forest residue, waste paper |
| Blended Fuels[b] | |
| RFG3 | Blended in CA, CARBOB, E100 corn |
| E10 corn | Blended in CA, CARBOB, E100 corn |
| E65 corn | Blended in CA, CARBOB, E100 corn |
| E85 corn | Blended in CA, CARBOB, E100 corn |
| Biodiesel BD2 | Blended in CA, ULSD, Biodiesel |
| Biodiesel BD20 | Blended in CA, ULSD, Biodiesel |
| FTD33 | Blended in CA, ULSD, FTD |
| Gaseous Fuels and Electricity | |
| Electricity NG | NG power plant |
| CNG NG | NG pipeline |
| cH2 NG SR On-site | NG pipeline, local reformer |
| cH2 NG SR Offsite, LH2 Delivery | NG reformer, diesel truck |
| cH2 electricity | NG power, electrolyzer |

[a] From pressure let down facilities in California.
[b] RFG3 assumed to meet Federal oxygenate requirements and California reformulated gasoline specifications by blending with ethanol – 5.7% mass basis(2% oxygen, 2% x 46/16=5.75%). For other blended fuels, the blend fraction corresponds to the fuel designation on a volume basis. For example, E10 contains 10 % ethanol by volume.

## Liquid Fuels

These are fuels that can be used in vehicles. Their fuel cycle analysis follows a relatively straightforward path from feedstocks and other energy inputs to refining, transport, and distribution. These fuels can also be blended with other components.

## Blending Components

These components are combined to make other fuels and generally are not thought of as vehicle fuels, although some could be used as vehicle fuels (for example E100 from corn). For local emissions, blending components were analyzed in the fuel chain only through bulk distribution. A discussion of local distribution of these components was not analyzed.

## Blended Fuels

Blended fuels are composed of a mixture of blending components or other liquid fuels. The emissions associated with local fueling infrastructure are determined for these blended fuels. The distinction between the infrastructure steps involved with separate fuel streams to a blending terminal followed by local distribution seems to be a minor point; however, the logistical requirements are important. The suitability of different transportation modes was evaluated for blended fuel fuels. The local fuel cycle emission results are more accurate when the actual fueling infrastructure is considered instead of simply averaging the results for individual components.[12]

## Gaseous Fuels and Electricity

The final grouping of fuels includes those derived from natural gas and/or electric power. The analysis of emissions associated with electricity use was based on power generation from natural gas, as this resource is considered a marginal generation resource for California (Unnasch 2001). Many of the fuel production pathways for gaseous fuels are similar in that they involve both natural gas and power consumption. Most of the gaseous fuels used electric power for compression. Gaseous fuel blends such as mixtures of CNG and hydrogen are also possible. Such blends were not analyzed in this study.

### C.2.3 Appendix A Organization

This appendix provides information to describe the energy inputs and emissions associated with different fuel production steps and how these relate to fuel cycle emissions. The major assumptions and details of fuel production and distribution processes are described. The information is organized in the following sections:

**C.3 — Vehicle and Fuel Cycle Analysis**. Background information and definitions used in this study are included in this section.

**C.4 —Fuel Production Pathways**. For each fuel, the feedstocks, transportation modes, and other parameters that affect fuel cycle emissions are discussed. All of the fuel production pathways considered in this study and the impact of alternative pathways on emissions are identified.

**C.5 —Fuel Production and Transportation Efficiency.** Energy inputs for fuel production and transportation are compared for all fuel production pathways. Energy inputs are presented as efficiency values.

**C.6 — Local Emissions from Fuel Production and Distribution Processes.** Emission rates for steps in the fuel cycle are identified, with emphasis on emission sources in California. Data sources that determine the speciation of toxic components are described.

[12] These results are most important for local NMOG emissions where the vapor pressure of blended fuels is different than the average of the blended components.

**C.7 — Fuel Economy Assumptions.** The impact of vehicle fuel economy on fuel cycle emissions is evaluated.

**C.8 — Local Fuel Cycle Emissions.** Fuel cycle emissions in urban areas and the rest of California for $NO_x$, CO, PM, NMOG, and toxics are identified for each fuel. The emissions are broken down by fuel cycle steps with the goal of differentiating NMOG sources to allow for the determination of toxic components. The effect of fuel economy and fuel cycle emissions is also analyzed.

**C.9 — Comparison of Fuel Cycle Studies.** Presents GHG emissions and energy consumption for the fuel and vehicle cycle on a per unit energy basis. A discussion of vehicle fuel economy for various light and heavy-duty vehicles is provided. These assumptions enable energy inputs and greenhouse gas emissions to be stated on a per mile or per kilometer basis. Combining the GHG emissions per unit energy and vehicle fuel economy allows comparison of various fuels on a gram per mile basis.

**C.10 — Sources of California Fuels.** The prospects of expanding refinery capacity and marginal versus average emissions are examined.

**C.11 — References for Appendix C.**

**C.12 — List of Terms and Abbreviations.**

## C.3 Vehicle and Fuel Cycle Analysis

The analysis presented in this Appendix quantifies the air emission impacts for each of the petroleum reduction options in the main report. This analysis accounts for the reduction in vehicle tailpipe and evaporative emissions, as well as emissions associated with fuel production, transport, and storage. This section identifies the boundaries and approach to the fuel cycle analysis.

### C.3.1 Identifying Emission Sources Associated with Vehicle Operation

The analysis performed in this study estimates air emission impacts for vehicle operation and the related fuel cycle – those activities enclosed by the dashed box in Figure C-1. These activities have a direct connection to petroleum reduction and depend on miles driven. Fuel cycle emissions include emissions generated during the extraction of feedstocks, processing or refining, transport, and local distribution. The construction and decommissioning of facilities and building vehicles are discussed in Section C.9.

Many factors affect well-to-wheel fuel cycle emissions. The most significant parameters, shown in Table C-2, affect the amount of fuel or feedstock required in the fuel cycle, emission control requirements, or the composition of fuels.

Fuel production processes are categorized into eight production and distribution steps, shown in Table C-3. These phases are grouped into the categories of extraction, production, marketing, and distribution, which are later used for presenting emissions results.

**Table C-2: Effect of Study Parameters on Fuel Cycle Results**

| Parameter | Effect on Fuel Cycle Analysis |
|---|---|
| Timeframe | Affects emission rules, infrastructure capacity |
| Production Technology | Affects energy inputs, emissions |
| Region | Affects emission standards, transport distances |
| Vehicle | Fuel cycle emissions and vehicle $CO_2$ are proportional to fuel consumption. Assumed vehicle $N_xO$ and $CH_4$ proportional to fuel consumption. $CH_4$, $N_2O$, CO, vary with vehicle technology. |

**Table C-3: Fuel-Cycle Emissions Were Categorized into Eight Production and Distribution Steps**

| Step | Description |
|---|---|
| <u>Extraction</u> | |
| 1. | Feedstock extraction |
| 2. | Feedstock transportation |
| <u>Production</u> | |
| 3. | Fuel processing/refining |
| 4. | Fuel storage at processing site |
| <u>Marketing</u> | |
| 5. | Transport to bulk storage |
| 6. | Bulk storage |
| 7. | Transport to local fueling station |
| <u>Distribution</u> | |
| 8. | Local station distribution |

### C.3.1.1 Geographic Distribution

The region where fuel production occurs was tracked in the fuel cycle analysis. The study focuses on determining emissions in California. The emissions were segregated into urban and rural areas.

Geographic distribution of pollutants are analyzed in order to identify the regions affected by various phases of the fuel cycles. This helps to evaluate the impact on local emission inventories and air quality as well as to take into consideration the differences between local emission rules. Although this analysis is not necessary for greenhouse gases, which have global impacts, the activities leading to local emissions often cause greenhouse gas emissions as well. As a result, the study also geographically distributes greenhouse gas sources. The percentage of feedstock extracted or fuel produced in each area is determined. Emissions from fuel production can then be allocated according to the locations in Table C-4. This table also shows the acronyms used to identify each of these areas for this report.

**Table C-4: Locations of Emissions**

| Location | Acronym |
|---|---|
| Within the SoCAB | SC |
| Within California, but outside the SoCAB | CA |
| Within the U.S., but outside of California | US |
| Rest of the World, outside the U.S. | ROW |

SoCAB = South Coast Air Basin.

In addition to emissions from fuel production, emissions for fuel or feedstock transportation and distribution are also divided into the four geographic distribution categories. For example, emissions for ships entering and exiting the San Pedro ports were attributed to the SoCAB for a portion of the trip. The balance of these emissions was attributed to the rest of the world. Both land and sea transport emissions were allocated proportionally according to their transport route.

Fuel cycle emissions are grouped by fuel production steps and facility location. Such groupings were extensively presented in the 1996 Acurex study and were the direct result of data base calculations (Unnasch 1996). For this study, groupings of emissions were obtained by tracing energy consumption in the fuel chain.

The timeframe for the analysis is beyond the year 2010 and corresponds to scenarios for a growing demand for gasoline. By the year 2020, baseline gasoline demand will be 19 billion gallons per year, according to the California Energy Commission's study on reduction of gasoline and diesel demand (CEC 2002). With the most aggressive petroleum reduction strategies analyzed by the Energy Commission, gasoline demand would drop to 12 billion gallons per year. This consumption level plus demand from Nevada and Arizona would be sufficient to keep California refineries operating at capacity.

#### C.3.1.2 Marginal Emissions

This study is intended to evaluate global greenhouse gas and local emissions from marginal fuel production. The interpretation of which emissions correspond to marginal fuel production depends on several factors that are discussed in the following section. The study looks at local emissions from the perspective of exposure to an individual in a locality, such as the SoCAB. Although the total emissions from marginal fuel production and transportation are important, an individual in one location is only exposed to local emissions. Therefore, for criteria pollutants, the scope of the study includes only the emissions generated in the SoCAB from incremental fuel use.

The analysis presented here is aimed at identifying marginal emissions associated with large volume fuel distribution. In the view of the authors, production capacity in California and many other regions involved in the logistics of fuel supply are well enough understood that a first order estimate of the marginal sources provides a good basis for the study assumptions. In order to meet California and worldwide demand for most of the fuels considered in this study, new growth in production capacity will be required. Any increases in fuel production or power generation due to a reduction in petroleum use were assumed to come from new, more efficient plants built to meet growing demand.

A more rigorous economic analysis could provide more detail on marginal energy production impacts. An economic analysis would take into account the supply and demand elasticities where reductions in the usage of one fuel would affect its supply, price, and other aspects of the economy. Comments from industry experts indicated that future marginal gasoline supplies would clearly come from out of state sources[13].

Another consequence of a marginal analysis is that no hydroelectric or nuclear power is included in the electric generation mix. Reducing gasoline demand by increasing electric power output for EVs does not increase the output from these types of generation facilities. The marginal source of electric power was assumed to be natural gas based on CEC's resource planning (CEC 2001, Tanghetti). This conclusion was also reached in an ITS Davis Study (Delucchi 1996).

Substantial transportation distances were assumed for the natural gas used to fuel CNG and hydrogen vehicles. Some analysts argue that natural gas resources in the U.S. are limited, and if hydrogen FCVs or CNG vehicles are used on a large-scale basis, additional natural gas would need to come from foreign sources of LNG. In this analysis, foreign sources of LNG were not included, but pipeline transportation from Canada was included. This pipeline transportation requires a substantial amount of energy and results in higher GHG emissions for natural gas or natural-gas-derived fuels.

The focus on marginal emissions raises questions of transporting emissions in and out of the state. For example, methanol could be sold for vehicle use in the SoCAB without any production emissions affecting local air quality. Similarly, gasoline is transported to other states from the SoCAB, while the refinery emissions contribute to emission inventories in the SoCAB. In both of these cases, this study's methodology excludes these emissions from consideration.

Some environmental groups and researchers consider the results of the marginal analysis in this study as optimistically low. Indeed, the marginal emissions are lower than average emissions. However, both electric and liquid fueled technologies are being compared on a marginal basis. In the authors' view, marginal emissions represent the contribution to the air that we breathe. Only substantial changes in the environmental and economic structure of fuels would result in emissions equal to the average emissions from refineries. For example, if new refineries were to be built in California or if capacity were increased beyond currently permitted levels, the contribution to air emissions on the margin would need to be reexamined. In principle, new petroleum refineries could be constructed in California and emission offsets could be obtained. However, the use of new fuels, such as reformulated diesel, for PZEV vehicles in California would not trigger such infrastructure changes.

The emphasis on marginal emissions by industry groups was a key outcome of the 1996 ARB Fuel Cycle study (Unnasch 1996). Industry groups and State agencies ultimately agreed that a

[13] The marginal source of gasoline was extensively reviewed with oil industry participants in prior ARB fuel cycle studies (Unnasch 1996, 2001).

marginal approach was relevant in the context of a moderate usage of alternative fuels. Another point of view is that a very substantial use of alternative fuels could result in a reduction in refinery capacity. Given the limited refinery capacity and substantial growth in gasoline demand, this outcome is unexpected.

The emission impact of displacing a very large fraction of refinery capacity with alternative fuels is not analyzed here. Even if such a scenario were to occur, it is uncertain that average emission rates would accurately reflect the impact on emissions, as the disposition of emission permits and offsets would need to be taken into account.

Given that California gasoline demand is expected to exceed California refinery production in future years, this analysis considers the following possible means for meeting future gasoline – and hence, petroleum – demand:

- Reducing petroleum demand through increased vehicle fuel efficiency and/or reduced vehicle use
- Avoiding petroleum use by using alternative fuel vehicles in place of conventional-fuel vehicles
- Importing refined petroleum products from other states and/or from outside the U.S. to meet the growing fuel demand

For this analysis, we assumed that petroleum displacement measures will not bring state fuel demand below current state refinery capacity within the time frame considered (i.e., 2002-2030). With this in mind, any measure to reduce future petroleum demand will impact only the amount of fuel imported from out-of-state, as there will still be ample demand for state refineries to produce at full capacity.

The principal assumptions that relate to these considerations include the following:

- Import liquid fuels to California (except ethanol from biomass)
- Produce marginal electric power from fossil fuels projected to be natural gas
- Marginal natural gas originates outside California
- RECLAIM limits $NO_x$ from power plants (and oil refineries but we are importing the fuel anyway)

### C.3.2 Fuel Properties

Table C-5 shows fuel properties that provide inputs for the analysis in this study. The values represent typical compositions. Some fuels such as gasoline, diesel, LPG, FTD, natural gas, and residual oil vary in composition while methanol, hydrogen, and ethanol are pure compounds. Variations in fuel properties are only due to contaminants.

**Table C-5: Fuel Properties — Metric Units**

| Fuel[a] | H/C | MW (g/mole) | Density[b] (kg/m³) | RVP (kPa) | HHV (MJ/kg) | LHV (MJ/kg) | HHV (MJ/L) | LHV (MJ/L) | Carbon Content: Mass Fraction | Carbon Content: Energy Specific[c] (g C/MJ) | Carbon Content: Energy Specific[c] ($gCO_2$/MJ) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline[d] | 2.02 | 92.0 | 719 | 58 | 48.4 | 44.7 | 34.8 | 32.1 | 85.5% | 19.1 | 70.2 |
| CARFG3[d] | 2.07 | 89.7 | 722 | 47 | 47.2 | 43.5 | 34.1 | 31.4 | 84.2% | 19.3 | 70.9 |
| CARBOB[d] | 2.02 | 96.0 | 719 | 47 | 47.9 | 44.2 | 34.5 | 31.8 | 85.5% | 19.3 | 70.9 |
| Diesel, No. 2 | 1.71 | 170.2 | 863 | 0.15 | 46.5 | 42.6 | 40.2 | 36.7 | 87.5% | 20.5 | 75.3 |
| ULSD[e] | 1.80 | 154.8 | 830 | 0.15 | 44.7 | 42.8 | 37.1 | 35.5 | 86.9% | 20.3 | 74.4 |
| Residual oil | 1.60 | 177.1 | 971 | 0 | 45.0 | 42.0 | 43.7 | 40.8 | 88.2% | 21.0 | 77.0 |
| LPG | 2.63 | 44.0 | 504 | 930[f] | 50.2 | 46.0 | 25.3 | 23.2 | 81.9% | 17.8 | 65.3 |
| Propane | 2.67 | 44.1 | 510 | 930[f] | 50.4 | 46.4 | 25.7 | 23.7 | 81.7% | 17.6 | 64.6 |
| Natural Gas | 3.85 | 16.6 | 0.81 | — | 52.3 | 47.2 | 0.042 | 0.038 | 74.1% | 15.7 | 57.6 |
| LNG | 3.89 | 16.3 | 420 | 414[f] | 53.8 | 48.5 | 22.6 | 20.3 | 75.4% | 16.0 | 58.5 |
| Methane | 4.00 | 16.0 | 0.78 | — | 55.6 | 50.0 | 0.043 | 0.039 | 74.9% | 15.0 | 54.9 |
| Methanol | 4.00 | 32.0 | 792 | 32 | 22.8 | 20.0 | 18.1 | 15.8 | 37.5% | 18.7 | 68.7 |
| FT, Diesel Oil | 2.14 | 127.5 | 780 | 0.15 | 47.2 | 43.9 | 36.8 | 34.2 | 84.8% | 19.3 | 70.6 |
| FT, Naphtha | 2.26 | 100.0 | 703 | 0.15 | 47.8 | 44.5 | 33.6 | 31.3 | 84.1% | 18.9 | 69.3 |
| Ethanol | 3.00 | 46.1 | 785 | 15.9 | 29.8 | 27.0 | 23.4 | 21.2 | 52.1% | 19.3 | 70.8 |
| Biodiesel | 1.38 | 123.2 | 884 | 16.9 | 40.5 | 36.9 | 35.8 | 32.6 | 78.0% | 21.1 | 77.5 |
| LH2 | — | 2.0 | 69 | 160[f] | 142.1 | 119.9 | 9.8 | 8.2 | 0.0% | 0.0 | 0.0 |
| Hydrogen | — | 2.0 | 0.10 | — | 142.1 | 119.9 | 0.014 | 0.012 | 0.0% | 0.0 | 0.0 |

[a] Heating values are for liquids except for natural gas, methane, and hydrogen.
[b] Density for natural gas, methane, and hydrogen are for gases at 1 atm, 25°C.
[c] Carbon per MJ, LHV basis. Includes total carbon in fuel. Actual $CO_2$ from combustion will be lower due to CO, HC, and $CH_4$ emissions and vehicle evaporative losses.
[d] Gasoline without oxygenate, available in California before 1990. RFG3 based on meeting 2% oxygen by mass with 5.7wt% ethanol (5.3vol%). CARBOB (California Reformulated Gasoline Blendstocks for Oxygenate Blending) is the blending component for RFG3.
[e] Ultra low sulfur diesel, 10 ppm sulfur.
[f] Represents storage pressure. For LPG, pressure at 25°C. For LNG and LH2, maximum storage pressures. Note the lower estimated storage pressure for LH2. At elevated pressure equilibrium storage temperature would be higher and density would decrease, which would be impractical for most storage systems.

Sources:, DOE, Glassman, Heywood, Kanury, North American, Schmidt, Unnasch 1996, Weast.

Both conventional and future hydrocarbon fuels are shown in Table C-5. California RFG3 is blended with ethanol to meet oxygenate, benzene, vapor pressure, and other requirements. Ultra low sulfur diesel (ULSD) contains 10 ppm sulfur which is achieved through additional hydrotreating. The hydrotreating results in a higher H/C ratio, which also affects the heating value and density.

LPG is a mixture of various hydrocarbons, which are gases at atmospheric pressure and temperature but are stored as liquids at elevated pressure. Propane is the major constituent in LPG. LPG is a by-product of both natural gas processing and oil refining. In the United States, approximately 30 percent of the LPG is produced from oil refining and 70 percent is from natural gas processing. LPG from oil refineries contains propene, while LPG from natural gas does not. The propene content of LPG is limited to 5 percent for vehicle use.

Natural gas contains primarily methane, some higher saturated hydrocarbons, nitrogen, and $CO_2$. GRI and others have reported data on pipeline gas compositions (Liss). LNG is produced from the liquefaction of natural gas and is stored at -260°C.  Liquefaction removes almost all of the nitrogen, $CO_2$, and higher hydrocarbons, except for ethane.

Fischer Tropsch synthesis produces a variety of products ranging in density from naphtha to diesel to waxes.  Low temperature FT products are pure straight chain hydrocarbons.

Several plant oils are the primary component of biodiesel.  Soybean oil was the basis for the analysis in this study.  A reaction with methanol produces an ester, which stabilizes the vegetable oil.  Biodiesel is often blended with conventional diesel with the aim to reduce emissions.

Fuel properties have an important impact on fuel cycle and vehicle emissions.   The composition of fuels determines their combustion properties including heating value.  The elemental composition relates to $CO_2$ and $SO_2$ emissions.  Almost all of the carbon in fuel is converted to $CO_2$, and similarly almost all sulfur in fuel is converted to $SO_2$.  The hydrogen content of fuels relates directly to the amount of water vapor produced during combustion.  The difference between higher and lower heating values is the heat of vaporization of water vapor produced during combustion.  For many hydrocarbons a relationship occurs with hydrogen to carbon ratio (H/C) and density as well as H/C and heating value (Schmidt, North American, Unnasch 1996).

Fuel density directly affects the cargo capacity of delivery trucks.  Similarly, the energy required for tanker ship transport depends on the weight of the fuel.  The fuel density also relates the heating value per unit mass to the heating value per unit volume.  The density of gaseous fuels in Table C-5 is shown at atmospheric pressure.  Since gaseous fuels can be stored at various pressure and temperatures, the values are not shown for vehicle storage conditions.

The lower heating value (LHV) provides a basis for comparing fuel economy among fuel choices.  The comparison of vehicle fuel efficiency on an LHV basis for internal combustion engines and fuel cells is industry practice.  Both higher and lower heating value comparisons are typically used in industry for stationary fuel combustion.  For the fuel cycle analysis, all of the efficiency inputs and calculations are performed on an LHV basis.  Any HHV-based data was converted to an LHV basis.

Vapor pressure and fuel molecular weights are shown in Table C-5.  These properties are important in determining hydrocarbon emissions from storage and transport of these liquid fuels. The vapor density depends on vapor molecular weight and vapor pressure.  ARB completed an extensive evaluation of the composition of vapors from vehicle fuel tanks and storage containers. Several gasoline compositions and alcohol blends were tested.  These data were supplemented with model calculations and reported in an ARB study (Unnasch 1996). The vapor pressure of liquid fuels affects their evaporative emissions with the density of fuel vapors being proportional to the molecular weight of the vapors and vapor pressure.[14]  For liquefied gases, the storage pressure affects the vapor mass from nozzle disconnects and venting.

[14] For multi-component liquid fuels, the composition of fuel vapors differs from the liquid.  Furthermore, the composition differs with temperature.

Table C-6 shows the most widely used fuel properties in English units. This tabulation facilitates comparison with other studies and is helpful for calculation checks. Most of the fuel properties agree closely with those reported in the GREET 1.6 model (Wang 2001) and the values that differ have little impact on the outcome of the analysis.[15]

**Table C-6: Fuel Properties — English Units**

| Fuel[a] | HHV (Btu/lb) | LHV (Btu/lb) | HHV (Btu/gal) | LHV (Btu/gal) | Density[b] (lb/gal) | RVP (psi) | $CO_2$ Factor (lb/MMBtu)[c] (HHV) | (LHV) |
|---|---|---|---|---|---|---|---|---|
| Gasoline | 20,800 | 19,200 | 124,790 | 115,190 | 6.00 | 8.4 | 150.7 | 163.2 |
| CARFG3 | 20,400 | 18,820 | 122,960 | 113,430 | 6.03 | 6.8 | 151.3 | 164.1 |
| CARBOB | 20,600 | 19,000 | 123,600 | 114,000 | 6.00 | 6.8 | 152.2 | 165.0 |
| Diesel, No. 2 | 20,010 | 18,300 | 144,060 | 131,750 | 7.20 | 0.02 | 160.3 | 175.3 |
| ULSD | 19,210 | 18,400 | 133,080 | 127,460 | 6.93 | 0.02 | 165.8 | 173.1 |
| Residual oil | 19,350 | 18,060 | 156,720 | 146,270 | 8.10 | 0.03 | 167.1 | 179.0 |
| LPG | 21,570 | 19,770 | 90,800 | 83,230 | 4.21 | 135 | 139.3 | 152.0 |
| Propane | 21,669 | 19,950 | 92,230 | 84,910 | 4.26 | 135 | 138.3 | 150.2 |
| Natural Gas | 22,500 | 20,300 | 152 | 137 | 4.58 | — | 120.8 | 133.9 |
| LNG | 23,100 | 20,300 | 80,850 | 71,050 | 3.50 | 60 | 119.7 | 136.2 |
| Methane | 23,900 | 21,500 | 156 | 140 | 4.31 | — | 114.9 | 127.7 |
| Methanol | 9,800 | 8,600 | 64,770 | 56,840 | 6.61 | 4.6 | 140.2 | 159.8 |
| GTL, Diesel Oil | 20,638 | 18,918 | 134,340 | 123,140 | 6.51 | 0.02 | 150.6 | 164.3 |
| GTL, Naphtha | 20,853 | 19,133 | 122,340 | 112,250 | 5.87 | 0.02 | 147.8 | 161.1 |
| Ethanol | 12,800 | 11,600 | 83,850 | 75,990 | 6.55 | 2.3 | 149.4 | 164.8 |
| Biodiesel | 17,420 | 15,870 | 128,520 | 117,090 | 7.38 | 0.02 | 164.2 | 180.2 |
| LH2 | 61,100 | 51,550 | 35,040 | 29,570 | 0.57 | 23 | 0.0 | 0.0 |
| Hydrogen | 61,100 | 51,550 | 50.1 | 42.3 | 0.54 | — | 0.0 | 0.0 |

[a] Heating values are for liquids except for natural gas, LNG, methane, and hydrogen.
[b] Density for natural gas, methane, and hydrogen lb/100 scf.
[c] Lower heating value.
[d] Ultra low sulfur diesel, 10 ppm sulfur.

*Fuelprop.xls*

Several fuels analyzed in this study are blends. The composition of the blended fuels is shown in Table C-7 on a volumetric basis, which is typically used to describe fuel composition, particularly of alternative fuel blends. RFG3 requires 2 percent oxygen, which corresponds to 5.7 percent ethanol on a mass basis or 5.3 percent for volumetric blending. For fuel cycle energy and GHG calculations track the steps on an energy basis. The energy-weighted fraction of the blended fuels is shown in Table C-8. The lower heating value, which is typically used to compare the energy consumption for vehicles, is shown for the blended fuels.

[15] One notable exception is the carbon content of FTD fuel. The carbon content of FTD shown in Table A-5 was compared with various published values and reviewed with FTD developers. From a practical viewpoint, the carbon content of FTD fuels does not impact the final WTW fuel cycle analysis on a g/mi basis. $CO_2$ emissions from the fuel production process are calculated by a carbon balance method combining the efficiency of fuel production with the carbon content of the feedstock and fuel.

**Table C-7. Fuel Mixtures for Volumetric Blending**

| Component Blend (Vol %) | RFG3 | E10 | E65 | E85 | BD20 | FTD33 |
|---|---|---|---|---|---|---|
| CARBOB | 94.7% | 90% | 35% | 15% | — | — |
| E100 | 5.3% | 10% | 65% | 85% | — | — |
| Biodiesel | — | — | — | — | 20% | |
| FTD | — | — | — | — | — | 33% |
| RFD | — | — | — | — | 80% | 67% |

**Table C-8: Energy Fraction for Calculating GHG and Energy (LHV Basis)**

| Component Blend (J/J)[a] | RFG3 | E10 | E65 | E85 | BD20 | FTD33 |
|---|---|---|---|---|---|---|
| CARBOB | 96.4% | 93.1% | 44.7% | 20.9% | — | — |
| E100 | 3.6% | 6.9% | 55.3% | 79.1% | — | — |
| Biodiesel | — | — | — | — | 19.3% | — |
| FTD | — | — | — | — | — | 32.3% |
| RFD | — | — | — | — | 80.7% | 67.7% |
| Blend LHV (MJ/L) | 31.4 | 30.7 | 24.9 | 22.8 | 35.1 | 35.0 |

[a] Indicates proportion of each blending component as a ratio of mass fraction x LHV (g/MJ) divided by total mass fraction x LHV (g/MJ)

*emissions.xls*

### C.3.3 Analysis Methods

In the study, local and regional emissions of criteria pollutants are calculated using in-use and rule-based emissions factors for the steps in the fuel cycle. Since the rules primarily govern fuel and vapor transfers on a volumetric basis, the local emissions are also tracked per unit of volume. GHG emissions, on the other hand, are calculated using energy efficiency factors for the fuel cycle, which are inputs to the GREET model. A composite of several results from GREET provide the GHG values for some fuel cycles.

Determining fuel cycle emissions requires a detailed tracing of the steps involved in the production and distribution of fuels. Several studies consider these calculations (Unnasch 1989, Delucchi 1993, Unnasch 1996, Lasher 2002, Wang 1999) which include the following:

- Energy consumption is determined for all steps in the fuel cycle. Energy consumption and related combustion emissions are the principal source of GHG and criteria pollutant emissions in the fuel cycle.

- The energy consumption in the full fuel cycle includes not only the direct energy consumption of fuel production and transport equipment but also the energy required to produce the fuel in the fuel cycle.

- $CO_2$ emissions for combustion or fuel conversion are calculated from carbon content of the fuel or feedstock[16]

- $CH_4$ and $N_2O$ emissions depend on the type of equipment and are based on emission factors or fuel combustion

Key assumptions that affect the fuel cycle energy and GHG emissions include feedstock extraction and refining efficiency, energy requirements for feedstock and fuel transport, and the feedstock resource mix and related carbon content. These input assumptions were modified in the baseline GREET model to reflect the assumptions discussed in the following section. The details of the fuel cycle analysis are considered in the GREET 1.6 model which was developed by Argonne National Laboratory (Wang 2001). This model was used to determine energy inputs and GHG emissions for the fuel cycle. The outputs of the GREET model were used to develop the results presented in this study.

Some enhancements to the analysis and presentation of the results in the GREET 1.6 model were included in this study. These include the following:

- In addition to fuel cycle emissions, vehicle emissions are determined on a g/MJ basis. This approach prevents an inadvertent decoupling of the vehicle and fuel cycle results by readers of this study. The fuel cycle results for a particular fuel often correspond to the fuel properties, which affect the vehicle GHG emissions.

- Results from GREET 1.6 were determined for several "primary fuels". The fuel cycle results for the primary fuels were used to determine the energy inputs and GHG emissions for fuels such as CNG where multiple feedstocks are required from different regions. For example CNG would be produced from natural gas distributed throughout the U.S. and electric power produced both inside and outside California[17].

- Detailed calculations of local fuel distribution emissions were used to determine emissions in the SoCAB. This analysis allowed for a better tracking of the vapor pressure of blending components and delivered fuel products. The effect of ARB emission regulations was also tracked for each of the fuel distribution processes.

## Energy and GHG Calculations

The approach for determining energy inputs and GHG emissions corresponds to the following steps:

[16] In the case of fuel processes that involve a conversion of one feedstock to a fuel, the $CO_2$ emissions are typically determined using a carbon balance method. Carbon emissions = carbon in feedstock – carbon in product fuel – carbon in plant emissions. Delucchi 1993, Appendix C.6 describes the accuracy of a rigorous treatment of carbon emissions.

[17] GREET1.6 does allow for fuels and feedstocks from different regions to be used in the analysis. However, combining the results off model provided for better transparency and also eliminated a calculation issue when both electric power and natural gas power were assumed for hydrogen liquefaction facilities. Off model calculations also allow for a simple analysis of different hydrogen production scenarios.

1. Select fuel, feedstock, pathway, and vehicle combinations.

2. Determine California specific assumptions for location of fuel production, transportation distance, emission rates, and fuel properties.

3. Determine fuel production efficiency, energy inputs for fuel transportation, and gaseous fuel compression/liquefaction.

4. Steps 1-3 provide inputs to determine energy usage and GHG emissions from GREET 1.6 for "primary fuels" including:

   - ULSD, CARBOB and residual oil from petroleum produced in overseas refineries
   - E100 from corn and biodiesel from the Midwest U.S.
   - Natural gas produced in the U.S.
   - Electric power produced in California
   - Remote natural gas (RNG) or Non-North American natural gas feedstock for methanol, FTD, and LNG production

5. Determine vehicle CO, $CH_4$, and $N_2O$ emissions on a g/MJ basis.

6. Calculate vehicle $CO_2$ emissions from fuel properties.

7. Combine results for primary fuels for mixed feedstock and blended fuel results (RFG3, E10, E65, E85, BD2, BD20, CNG, $cH_2$ On-site SR, $cH_2$ SR LH2). This requires determining the amount of fuels or feedstock that are required on an energy basis rather than a volumetric basis.

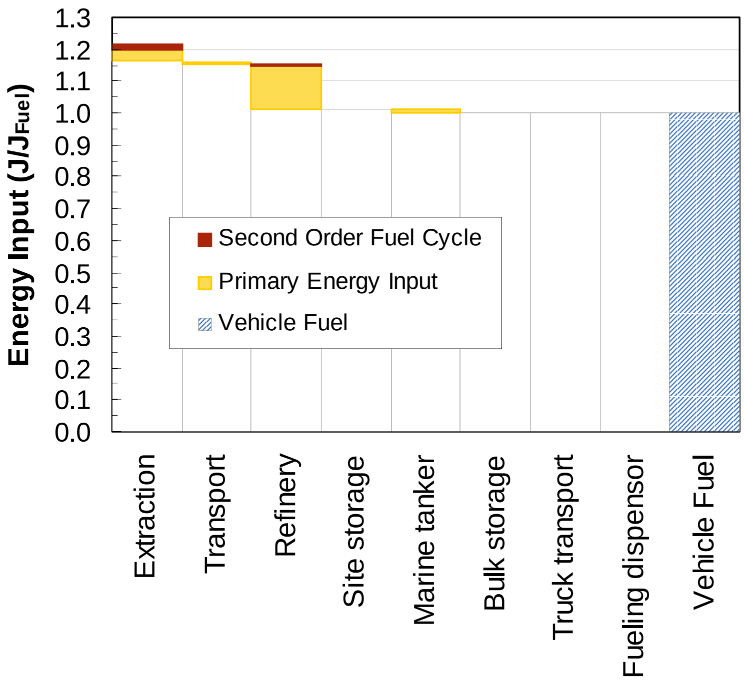
8. Calculate fuel cycle and vehicle cycle emissions.

9. Convert results to g/unit fuel basis for use in the main volume of this report.

**Fuel Cycle Energy Efficiency**

Figure C-9 shows the energy inputs for ULSD production, illustrating some of the composite efficiency of each fuel cycle step. The shaded bars indicate energy use for each step in the fuel cycle. The bar without shading represents the total energy consumed in the adjacent step. For each step, the ratio of the bar without shading divided by the total bar height represents the composite efficiency of each step. This efficiency value takes into account all of the energy inputs in a fuel cycle step.

**Figure C-9: Energy Inputs for ULSD Production**




In the case of ULSD, 1.21 units of energy are required for each unit of fuel product[18]. As the feedstock ultimately ends up in the fuel, the fuel is also indicated in this graphic. Most of the energy in the fuel cycle is petroleum and natural gas feedstocks to the oil refinery. About 88 percent of this energy is converted to diesel when all of the refinery inputs are allocated to products. Additional petroleum is required for extracting the crude oil and marine vessel and truck transport. These energy inputs correspond directly to input assumptions for the GREET model and are represented as "Primary Energy Input" in Figure C-9. Producing the energy required for the fuel cycle also requires energy. These energy inputs are determined in detail with fuel cycle models (Wang 2001, Unnasch 1996, Delucchi 1993) and are calculated by the GREET model. These second order energy inputs, also shown in Figure C-9, are a fairly small portion of the fuel cycle. The efficiency assumptions and analysis that affect the primary energy inputs have the largest impact on fuel cycle emissions.

The primary energy inputs are readily determined with a chain calculation where the energy used in each step $E_{I+1}$ is represented by the efficiency such that:

[18] This ratio is labeled as J/J to provide units for a non-dimensional value.

$$E_{I+1} = \eta_i \times E_I \qquad C\text{-}1$$

For simplified fuel chains with one feedstock the total energy ($E_T$) can be calculated by starting with the product fuel ($E_F$, consumed by the vehicle) and working backward to the extraction of feedstocks. Each upstream step would provide the fuel product plus processing energy for the next step. If all of the energy inputs are expressed as efficiencies then the total energy becomes

$$E_F = E_T \times (\eta_1 \times \eta_2 \times \ldots \eta_n) \qquad C\text{-}2$$

Again for a simple fuel cycle, the energy consumption for each individual step becomes:

$$\frac{E_i - E_{i+1}}{E_{i+1}} = \frac{1-\eta_i}{\eta_i} \qquad C\text{-}3$$

Where $E_i$ represents the total energy required in the fuel cycle including the fuel, $\eta_i$ the efficiency, and $E_i - E_{i+1}$ represents the energy consumed in step i.

Several complexities arise when this approach is applied to fuel cycles with multiple feedstocks. GREET deals with multiple feedstocks by performing separate fuel cycle calculations for each feedstock. The fraction of different fuels contributing to the fuel cycle is tracked and used to partition the energy and GHG emissions for each feedstock and fuel. The difference between an accurate fuel cycle calculation and the simple chain analysis shown in equations C-1 though C-3 depends on how the fuel cycle steps are defined and the mix of feedstocks. For ULSD, the difference is represented by the second order fuel cycle values in Figure C-9.

For this study, GREET 1.6 was used to perform the total fuel cycle calculations for several reasons. The model deals with second-order fuel cycle emissions in a convenient manner. Also, the authors completed a study for DOE based on GREET with modified input assumptions (Lasher). GREET analyzes biodiesel and ethanol from corn with an extensive review of the agricultural inputs. The open availability of GREET and the observation that GREET results matched TIAX in-house model results for test cases with identical assumptions was also a compelling reason to use the GREET model. The outputs from the GREET model present some challenges which were overcome by preparing a post processing model that combined results for primary fuels with analysis for different fuel production technologies. These post processing calculations could have been performed in the GREET model; however with less transparency of the intermediate results.

GREET results readily provide a grouping of the resource mix in the fuel cycle; however, the results are not readily determined by fuel cycle step. The 1996 ARB/Acurex study (Unnasch 1996) used a database approach to group fuel cycle calculations by feedstock, geographic location, and production step. This approach allowed for not only the tracking of the energy inputs by fuel cycle step but also the output by fuel cycle step or any other grouping. In Figure C-9, inspection of the energy input assumptions, off-model calculations, and comparing the results with intermediate values from the GREET model allowed for the presentation of energy use by fuel cycle step.

## Urban Criteria Pollutant Calculations

A separate set of calculations outside the GREET model determine criteria pollutant and toxic emissions in California. GREET calculations were used to estimate emissions outside California. Regulatory requirements vary from the SoCAB, California, other parts of the U.S. throughout the world. Also the details of local fuel distribution chain are more complex than the input assumptions for GREET.

The sum of fuel production and distribution emission sources in California take into account the vapor pressure of the product, composition of vapors, and regulations that apply to each distribution step. This accounting also allows for the determination of toxic air contaminants, which depend on the composition of fuel vapors (primarily for gasoline and ethanol blends).

Urban criteria pollutants are estimated and grouped as California and outside California emissions. Emissions sources within the SoCAB are counted as 100 percent in urban areas. No consideration is made for the spatial distribution of SoCAB emissions.[19] Emissions outside the SoCAB, within California were multiplied by 0.05 to reflect an assumption of population density and location of emission sources in proximity to urban areas. 26 kn of marine vessel operation was counted in the SoCAB and port of destination outside California. Finally, emissions outside California were assigned an estimate of urban emissions described in the following section.

The approach for determining criteria pollutant emissions corresponds to the following steps:

1. Select fuel, feedstock, pathway, and vehicle combinations.

2. Identify local California emissions. California specific assumptions for local fuel production are also an input to energy and GHG calculations. The parameters that affect urban emissions are location of fuel production facilities, rules governing fuel vapor emissions from storage facilities, fuel stations, stationary engines, power plants, as well as caps on power generation emissions.

3. Estimate fraction of emissions, which occur in urban areas. For outside California, baseline GREET values were used, except for marine vessel operation. Transportation distances determine emissions for delivery trucks, rail car, pipelines, and marine vessels. Assume 5 percent of emissions outside the SoCAB are in heavily populated urban areas.

4. For liquid fuels, determine combustion emissions for marine vessel, rail car, pipeline, and truck transport. These emissions depend on energy consumption and cargo capacity for each transportation mode. The cargo capacity determined for each fuel based on density and experience with fuel transport.

5. For gaseous fuels, determine natural gas and electricity inputs from the energy and GHG analysis. Combustion emissions for natural gas pipeline transport in the SoCAB and

[19] For liquid fuels, most emissions in the SoCAB are due to fuel storage and transport at port facilities. Biodiesel, and some ethanol, LPG, and LNG may be imported by rail. Power plants in the SoCAB are mostly along the ocean.

California were based on transportation distance, energy use factors, and emission standards governing IC engines. Calculate emissions from power plants taking into account the $NO_x$ cap in the SoCAB.

6. Determine hydrocarbon losses in California for production steps 4, 6, and 8. For liquid fuels stored at ambient pressure (RFG3, ULSD, etc.). Emissions are the lower of either the limit specified by ARB and local regulations or the amount calculated from vapor pressure, molecular weight, tank configuration, combined with saturation factors used in previous inventory estimates. For LPG and LNG, calculate emissions from fuel transfer operations and make estimates for future emission controls.

7. For combustion NMOG emissions and hydrocarbon losses, determine air toxic emissions based on ARB speciation data. Identify formaldehyde, acetaldehyde, 1-3 butadiene, and benzene emissions. The speciation profiles differ for RFG3 liquid spills, refueling vapors, and vehicle vapors.

8. Use urban emission values from GREET, to estimate emissions outside California. Add marine vessel emissions for 26 kn.

9. Sum the results for use in the Task 1 report on a g/unit fuel basis.[20]

10. Convert the results to g/GJ for presentation in this Appendix.

## C.4 Fuel Production Pathways

This section of the appendix discusses the steps in the fuel cycle for each of the fuels and feedstocks considered in the study. The energy inputs for fuel production and distribution are presented according to the eight production and transportation steps indicated earlier in Table C-1. These energy inputs are discussed in relation to their impact on each fuel chain. The energy inputs for different fuel chains are discussed in Section C.5.

### C.4.1 Petroleum Fuels

Petroleum fuels analyzed in this study include CARBOB, the blending component for RFG3, ULSD, and LPG. Energy inputs and emissions associated with residual oil production were also analyzed, as residual oil is used for marine vessel transport. Residual oil is also a byproduct of refining and the fate of residual oil is also considered.

#### C.4.1.1 Source of Petroleum Products

The analysis of petroleum production and related emissions is based on displacing imported gasoline and diesel products to California. Since LPG from overseas refineries is not likely to be imported the California, the fuel cycle for LPG represents imported crude oil with production in California refineries.

[20] Units of commerce are: 100scf for CNG, kg for hydrogen and LH2, kWh for electricity, actual gallons for all other fuels.

Although a significant fraction of crude oil for California refineries is produced in the State, California production is estimated to remain constant for a change in diesel or gasoline consumption[21]. With limited refinery capacity, additional product may be imported to California or refinery operations may be modified. As a result, increased diesel or gasoline use does not lead to incremental local emissions from oil production (see Section C.10 discussion on marginal emissions). With extensive analysis of the supply/demand elasticity of future petroleum products in California, the projections of oil industry experts and the consensus of energy industry stakeholders was that gasoline would be imported to California on the margin (Unnasch 1996, Unnasch 2001, ARB 2000).

As a first order estimate, local emissions from refineries are independent of diesel, gasoline, or LPG demand[22]. If gasoline demand were reduced, it is likely that imports of finished gasoline would simply be reduced while operations remain constant at local refineries. Increased diesel demand at the expense of gasoline sales could be met by increasing the mix of diesel products that are imported to the SoCAB or by adjusting refinery operations to produce more diesel. Analyzing the effect of changing the shift in refinery products ideally would be accomplished by a linear programming (LP) model that optimizes all of the refinery streams for an optimal economic and fuel specification output. Such LP analyses primarily are aimed at analyzing the effect of different fuel formulations or refinery process configurations.

#### C.4.1.2 Gasoline, Diesel, and LPG Production

Crude oil is refined into a variety of products including primarily gasoline or CARBOB, kerosene, diesel, LPG, residual oil, waxes, sulfur, and coke. The crude oil production and processing steps apply to all of the petroleum products because the feedstock is the same. Various refinery units produce a mix of products. Energy consumption for each refinery unit was allocated to the products to determine the efficiency of fuel production.

In addition to gasoline, distillate fuel, and LPG, oil refineries produce products such as residual oil, coke, sulfur, and asphalt[23]. The fate of the byproducts, especially residual oil can effect the GHG emissions associated with fuel production (gasoline, diesel, and LPG). Residual oil is used as fuel for marine vessels and power plants. Additional residual oil supply would have and impact on prices and demand for marine vessel fuel but much of the additional fuel could be used for power plant fuel where it would displace coal or natural gas. Displacing coal-based power with residual oil reduces GHG emissions while displacing natural gas based power increases GHG emissions. Residual oil might also be attributed to displacing nuclear or other non-fossil power where the GHG emissions from residual oil would be higher.

[21] California oil production responds to world oil prices, which are affected by California demand. California production is either at full capacity when prices are above a threshold of roughly $15/bbl, or it tapers of depending on each well's parameters. This report does not attempt to analyze the effect of changes in California production.

[22] The analysis in this report is based on imported gasoline and diesel. However, some shift in refinery mix might also be contemplated as a way of producing diesel.

[23] Not all refineries produce asphalt but it is an interesting product as it sequesters carbon in a form that is not combusted.

In this study, emissions the allocation of energy in the refinery by product determines emissions and emissions associated with the fate of residual oil are only discussed in the sensitivity analysis.

Table C-9 shows the steps in the fuel chain and the energy inputs for the production of ULSD. Also indicated are the local emission sources in California for the SoCAB fuel end-use scenario. The boundaries for the local emissions are relatively simple since the analysis is based on importing diesel product.

Table C-9 and a dozen similar tables in this report illustrate the most important assumptions in the fuel cycle analysis. The fuel production process for each step in the fuel cycle is identified. The type of emission source and the location of urban emissions are indicated. The fraction of emissions that occur in urban areas are represented by a percentage next to the location where they occur or by the transportation distance for the fuel or feedstock. The width of the feedstock graphic approximately corresponds to the amount of total energy in the fuel cycle and also represents the transformation from feedstock to fuel. The values at the bottom of the graphic also indicate the total fuel cycle energy input (including fuel) and the inverse of this value, which corresponds to the efficiency of fuel production.

The energy inputs and corresponding fuels listed for each step in the fuel cycle represent the fraction of energy used in each step. The ratio of energy consumed (Input/Output, J/J) reflects the energy consumed divided by energy that is passed to the next step. Energy input values in step 3 are greater than 1.0 because these include the feedstock (crude oil) which produces diesel. The shading in the graphic also reflects the feedstock consumption in step 3. The energy input values correspond to the assumptions in the fuel cycle analysis used in the GREET model. Additional calculations produced the breakout of energy use illustrated in Figure C-9.

The graphic in Table C-9 also shows the major energy inputs for diesel production. These values are "primary" energy inputs and are not shown in a total fuel cycle basis. The primary energy input is indicated as the "input fuel" in the table. The second order energy requirement and emissions are estimated using the GREET model. The primary energy inputs correspond to the inputs for GREET, although the GREET inputs are typically expressed as an efficiency. The efficiency of crude oil extraction is 94.6 percent based on analysis by Wang. This value is consistent with other sources (ADL Novem, Unnasch 1996). This conversion efficiency translates into 0.05 J of energy input per J of crude oil extracted[24]. The energy for input for refining is based on a refinery modeling study performed by MathPro (1999). The energy inputs for all of the refinery units in this study were segregated by product stream and output. This breakdown allows for the calculation that reflects the refining efficiency for diesel.

[24] Of course the total fuel cycle energy required per J of diesel is a larger value because of second order energy inputs such as the energy required to produce the oil which is used for crude oil extraction. These energy inputs are the purpose of fuel cycle models and the graphics here illustrate the magnitude of the inputs.

**Table C-9: Ultra Low Sulfur Diesel from Crude Oil-Production and Distribution Phases**

| | Process | Emission Sources | California Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Heaters, pumps | 0% ROW |
| 2 | Feedstock transport | Pipeline engines | 0% ROW |
| 3 | Refining | Refinery combustion, fugitives | 10% ROW |
| 4 | Site storage | Refinery tanks | 20% ROW |
| 5a | Transport to bulk storage | Tanker ship engines | 26 kn SC, 26 kn ROW |
| 6a | Bulk storage | Floating roof tanks | SC |
| 5b | Local transport | Pipeline engines | SC |
| 6b | Bulk storage | Floating roof tanks | SC |
| 7 | Transport to local station | Tanker truck engines | SC |
| 8 | Local station distribution | Storage tanks, dispenser | SC |

| | Process | J/J | Input Fuels | Feedstock | | Energy Calculations |
|---|---|---|---|---|---|---|
| 1 | Extraction | 0.037 | **Crude Oil, RNG** | **Crude Oil** | | |
| 2 | Transport | 0.005 | | | | |
| 3 | Oil Refinery | 1.122 | **Crude Oil** | | | |
| | | 0.012 | **RNG** | | | |
| | | 0.001 | **electricty** | | | |
| 4 | Site storage | | | | Energy Loss | *GREET 1.6 ROW* |
| 5 | Transport to bulk storage | 0.0113 | **Resid. Oil** | | | **ULSD, 10 ppm S** |
| 6 | Bulk storage | | | **ULSD** | | |
| 7 | Local truck transport | 0.0014 | **ULSD** | | Product Loss | |
| 8 | Tank, fueling dispenser | 0.0002 | | | | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Crude oil extraction efficiency is 96.9%. Extraction energy input is 0.037J/J crude oil. This is not the total fuel cycle energy, but only the energy per unit of crude oil. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery and processing losses are 0.35% and 0.15% respectively.
2. Pipelines transport crude oil and natural gas to refineries. Assumed 200 mi for crude oil transport to refineries and 400 mi for natural gas transport.
3. Refinery efficiency for 150 ppm diesel is 89.1% based on the allocation of refinery inputs and product streams in MathPro 1998. Additional hydrogen consumption of 150 scf/bbl is added for desulfurization to 10 ppm (MathPro 1999). Hydrogen is produced from reforming natural gas.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of storage facility emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. 150,000 DWT vessels transport ULSD to California. 5400 kn was assumed for transport distance. Smaller vessels might be used but these would more likely be used over shorter distances. Urban emissions are calculated for 26 kn of travel in the SoCAB and at the overseas port. In-port emissions are also included.
6. Storage emissions are calculated for floating roof tanks in the SoCAB.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery trucks and to the vehicle as well as fueling spillage. Product losses from steps 4, 6, and 8 are combined to determine total ULSD required in Step 3.

Additional energy input for hydrotreating is included in order to achieve 10 ppm sulfur. A hydrotreating level of 150 scf/bbl represents the difference between conventional diesel and diesel with 10 ppm sulfur. The refinery efficiency for diesel production without additional hydrotreating was estimated to be 89 percent.

Transportation energy inputs were based on assuming 150,000 DWT product tankers for all of the liquid fuels. Energy consumption per DWT drops for larger vessels. Wide ranges of marine vessels transport fuel today. Larger 150,000 DWT marine tankers rather than an average vessel mix were assumed for several reasons. Importing large volumes of fuel to California would make larger vessels more feasible. Also, results for ULSD and RFG3 are being compared to alternative fuels. Analyzing new dedicated vessels for alternative fuels and comparing these with results for a mix of product tankers for ULSD and RFG3 was considered unfairly biased against petroleum fuels (Unnasch 2001).

The diesel product is unloaded in Southern California and transported by diesel truck to local fueling stations. The principal energy input is diesel for the delivery truck. Product losses associated with fueling and bulk storage evaporation are counted in the full fuel cycle as these losses must be made up by producing and transporting additional product. As indicated in the figure, the effect of product loss, while included in the fuel cycle calculation is negligible. Total product loss is about 1 g/gallon.

The steps in the local storage and distribution of fuels represent a small fraction of the total energy but this activity is still important in terms of local emissions, which are identified and counted in Section C.5.

Table C-10 illustrates the energy inputs and steps involved in RFG3 production. The energy and GHG analysis is treated as combined production of CARBOB and ethanol from corn. The energy inputs for crude oil production are the same as those for diesel production on a percentage basis (J input/J of crude oil); however the total energy required for gasoline production differs due to the energy inputs required for the refinery and to a lesser extent product transport.

The energy inputs for CARBOB production are based on the MathPro study that result in a refinery efficiency of 83.9%. Note that the exercise of attributing energy inputs to refinery operations is not straightforward and requires some interpretation of what energy inputs should be assigned to gasoline. More detailed discussions of refinery energy allocation are discussed in studies by Acurex, Argonne National Laboratory, and NREL (Unnasch 1996, Wang 1999, Kadam).

The energy inputs required for tanker ship transport and local delivery truck transportation differ slightly from those for ULSD. These differences are due differences in fuel density and heating value as discussed in Section C.5.

**Table C-10: RFG3 from Crude Oil-Production and Distribution Phases**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Heaters, pumps | 0% ROW |
| 2 | Feedstock transport | Pipeline engines | 0% ROW |
| 3 | Refining | Refinery combustion | 10% ROW |
| 4 | Site storage | Refinery tanks | 20% ROW |
| 5a | Marine transport | Tanker ship engines | 26 kn SC, 26 kn ROW |
| 6a | Bulk storage | Floating roof tanks | SC |
| E100 | Ethanol blending component | Ethanol fuel cycle | See ethanol fuel cycle |
| 5b | Local transport | Pipeline engines | SC |
| 6b | Bulk storage | Floating roof tanks | SC |
| 7 | Transport to local station | Tanker trucks | 50 mi SC |
| 8 | Local station distribution | Dispenser and storage tanks | SC |

| Process | J/J | Input Fuels | Feedstock | | Energy Calculations |
|---|---|---|---|---|---|
| 1 Extraction | 0.037 | **Crude Oil,** | **Crude Oil** | | |
| 2 Transport | 0.005 | **RNG** | | | *GREET1.6 ROW* |
| 3 Oil Refinery | 1.161 | **Crude Oil** | | | **RFG, 0 oxygenate** |
| | 0.03 | **RNG** | | | **ULSD, 10 ppm S** |
| | 0.001 | **electricity** | | | |
| 4 Site storage | | | | Energy | |
| 5 Transport to bulk storage | 0.03 | **Resid. Oil** | | Loss | |
| 6 Bulk storage | | | **CARBOB** | | |
| 6b Blending component | | **E100 Corn** | | | *GREET1.6 US* |
| 7 Local truck transport | 0.0014 | **ULSD** | **CA RFG3** | Product | **Ethanol, Corn** |
| 8 Tank, fueling dispensor | 0.00017 | | | Loss | |
| **Fuel and Vehicle Cycle** | **1.311** | | **76.3%** | | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Crude oil extraction efficiency is 96.9%. Extraction energy input is 0.037J/J crude oil. This is not the total fuel cycle energy, but only the energy per unit of crude oil. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery and processing losses are 0.35% and 0.15% respectively.
2. Pipelines transport crude oil and natural gas to refineries. Assumed 200 mi for crude oil transport to refineries and 400 mi for natural gas transport.
3. Refinery efficiency for CARBOB is 83.9%. This value is based on the MathPro 1998 refinery study for CEC for zero oxygenate gasoline.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of storage facility emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. 150,000 DWT vessels transport ULSD to California. 5400 kn was assumed for transport distance. Smaller vessels might be used but these would more likely be used over shorter distances. Urban emissions are calculated for 26 kn of travel in the SoCAB and at the overseas port. In-port emissions are also included.
6. Storage emissions are calculated for floating roof tanks in the SoCAB.

6b. RFG3 energy inputs are 96.4% CARBOB and 3.6% ethanol from corn. The energy inputs in this table are for the petroleum fuel cycle. Fuel cycle and fuel results for gasoline production are also used to determine GHG emissions from ethanol blends.

7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery trucks and to the vehicle as well as fueling spillage. Product losses from steps 4, 6, and 8 are combined to determine total ULSD required in Step 3.

RFG3 contains 3.8 percent ethanol on a LHV energy basis. RFG3 energy inputs and GHG emissions correspond to the fuel cycle results for CARBOB and E100 from corn were weighted by LHV. As discussed in Section C.3, this calculation is performed from GREET1.6 results in order to provide greater transparency of the intermediate results and also facilitate calculations for other ethanol/gasoline blends.

After diesel and gasoline are produced in a refinery, they are stored in bulk tanks and distributed to fueling stations in tank trucks. Emissions resulting from the storage of petroleum and petroleum fuels consist of two main types: fugitive and spillage emissions. Fugitive emissions are hydrocarbon emissions that escape from storage tanks, pipes, values, and other sources of leaks. These emissions are generally greater for gasoline than diesel, due to its higher vapor pressure.

The low vapor pressure of diesel has generally resulted in limited requirements on vapor recovery from storage and fueling equipment. The vapor pressure from diesel is so much lower than that of gasoline, that the uncontrolled diesel vapor losses are less than 10 percent of gasoline emissions with 95 percent emission control. Vapor losses primarily occur when tank trucks are filled at the bulk terminal, unloaded at the fueling station, and during vehicle fueling. Spillage during vehicle fueling is also a significant source of emissions.

As indicated in Table C-10, the energy (and related fuel cycle emissions) associated with fuel storage and product losses is a very small fraction of the fuel cycle. In practice, the emissions associated with blended fuel distribution do not correspond exactly to the weighted average emissions because of differences in the fuel’s vapor pressure and vapor density. Therefore, the local fuel infrastructure emissions are calculated in greater detail in Section C.6.

#### C.4.1.3 LPG from Petroleum

The fuel-cycle steps for LPG parallel those for gasoline and diesel. Petroleum-based LPG would be produced from refineries in the SoCAB. LPG is refined, stored, and distributed as indicated in Table C-11. The primary energy input is crude oil for the refinery. The analysis was based on transporting crude oil to the SoCAB.

Since LPG from petroleum is produced in California refineries, the analysis is based on production within the state. This production pathway is different than that for gasoline or diesel; however, it is consistent with the modest amounts of LPG used in a future petroleum displacement strategy. In addition, LPG could also be available from natural gas sources. Directly importing LPG from petroleum sources to California was not analyzed.

**Table C-11: LPG from Crude Oil-Production and Distribution Phases**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Heaters, pumps, pipeline | 0% ROW |
| 2 | Transport | Tanker ship | 26 kn SC, 26 kn ROW |
| 3 | Refining | Refinery combustion | SC[b] |
| 4 | Site storage | Refinery tanks | SC |
| 5 | Transport to bulk storage | Rail car | 30 mi SC |
| 6 | Bulk storage | Pressurized tanks | SC |
| 7 | Transport to local station | Tanker trucks | 50 mi SC |
| 8 | Local station distribution | Above ground tanks, dispenser | SC |

| Process | J/J | Input Fuels | Feedstock | | Energy Calculations |
|---|---|---|---|---|---|
| 1 Extraction | 0.124 | **Crude Oil,** | **Crude Oil** | | |
| 2 Transport | 0.025 | **RNG** | | | |
| 3 Oil Refinery | 1.070 | **Crude Oil** | | | *GREET 1.6 CA* |
| | 0 | **$NG_{CA}$** | | | **LPG petroleum** |
| | 0 | **$electrcity_{CA}$** | | | ULSD, 10 ppm S |
| 4 Site storage | | | | Energy | |
| 5 Rail transport | 0.002 | **Diesel** | | Loss | |
| 6 Bulk storage | 0.0022 | | **LPG** | | |
| 7 Local truck transport | 0.0015 | **ULSD** | | Product | |
| 8 Tank outage, dispenser | 0.0003 | | | Loss | |
| **Fuel and Vehicle Cycle** | **1.1190** | | **89.4%** | | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

[b] $NO_x$ from refineries is capped by RECLAIM.

1. Crude oil extraction efficiency is 96.9%. Extraction energy input is 0.037J/J crude oil. This is not the total fuel cycle energy, but only the energy per unit of crude oil. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery and processing losses are 0.35% and 0.15% respectively.
2. 1,000,000 DWT vessels transport crude oil to California. 5400 kn was assumed for transport distance. Urban emissions are calculated for 26 kn of travel in the SoCAB and at the overseas port. In-port emissions are also included.
3. Refinery efficiency allocated to LPG production is 6,350 Btu/gal (HHV) or 93.5% efficiency. Energy inputs are based on the MathPro 1998.
4. Bulk storage tanks are pressurized. The refinery uses any vapors displaced by tank filling.
5. Some LPG will be hauled to bulk distribution terminals by railcar. Assume mi rail travel.
6. Bulk storage facilities release LPG from hose connect losses from loading and unloading. Bulk tanks also have outage valve losses. The outage valve losses were assumed to be 90% controlled in the future.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption.
8. Local fueling station emissions include hose disconnect losses for fuel transfer from delivery trucks and to the vehicle. Also, outage valve losses also occur on the vehicle and storage tanks. A 90% reduction in these emissions was assumed. Product losses from steps 4, 6, and 8 are combined to determine total ULSD required in Step 3.

An important consideration is the fuel that the refinery LPG displaces. The analysis presented for LPG is a first order approximation since it appears unlikely that California refineries will increase their LPG production to meet vehicle demand. Refinery LPG could displace LPG from natural gas. Alternatively, natural gas fuel could displace LPG sold from refineries.

Important factors that affect LPG fuel cycle emissions include the mode for local transportation and the extent of vapor control during storage and vehicle tank fills. Improved vapor controls were assumed for LPG transfers (See Section C.4.2.2 and C.6.4).

### C.4.2 Natural Gas Based Fuels

Several of the fuels considered in the study are produced from natural gas. These include methanol, FTD, LPG, LNG, CNG, and hydrogen. The fuel cycles of these fuels are briefly described below. For CNG, FTD, methanol, and hydrogen, the fuel cycle energy inputs and emissions were calculated from the energy-specific results for primary fuel chains. The simplest example is CNG where the fuel cycle energy for natural gas combined with the fuel cycle energy for electric power for compression result in the fuel cycle energy for CNG. Natural gas fuels are broken down by remote natural gas from outside North America (also referred to as non-North America natural gas). These fuels are distributed as liquids by marine tankers. North American natural is distributed by pipeline for CNG and hydrogen production.

Both renewable and other fossil feedstocks can potentially be converted to these natural gas base fuels. Information on these alternative feedstocks is discussed with each fuel option but the fuel cycle results are not analyzed in this study.

#### C.4.2.1 Remote Natural Gas

**Synthetic Diesel from Natural Gas**

Synthetic fuels can be produced from the catalytic reaction of CO and hydrogen. The Fisher Tropsch (FT) Process is one process that has been developed for fuel production. In recent years, developments in catalysts have allowed for the production of fuels in the diesel boiling point range. Synthetic diesel and FT Diesel are categorized together as all approaches for producing synthetic diesel are conceptually similar and result in the same emissions impact in California.

The FT Process was originally developed in Germany in the 1920s to produce diesel from coal. FT plants are also operating in South Africa and Russia to make synthetic gasoline from coal. Currently FT plants are being constructed to use remote natural gas as a feed stock. FT fuels potentially can be produced from renewable sources such as biomass.

Major oil companies are supporting the development of FT fuels or gas-to-liquids (GTL) products. Shell, BP, ExxonMobil, and ChevronTexaco have built or are planning to build production facilities. Developers like Syntroleum are also working on FTD processes, some aimed at smaller scale facilities (ICRC). Oil companies own many of the natural gas fields in the world and are interested in finding a market for the fuel. Exxon included an article describing its GTL technology in their 1998 publication for shareholders which illustrates their interest in the technology (Weeden, GTL Progress, 2001).

The FT Process has three principal steps. First, a feedstock is converted to synthesis gas, a mixture of carbon monoxide and hydrogen. Potential feedstocks include coal, biomass, and natural gas. A catalytic reactor converts the synthesis gas to hydrocarbons in the second step. The mixture of hydrocarbons consists of light hydrocarbons and heavier waxes. In the third step, the mixture of hydrocarbons is converted to final products such as synthetic diesel fuel. Most developers are working on "low temperature" cobalt based catalysts. The FTD product from all of these processes contains saturated hydrocarbons and contains no aromatics. Higher temperature processes may produce a product that contains aromatics and was not considered in this study.

The energy inputs associated with FTD production are illustrated in Table C-12. The analysis of energy inputs and GHG emissions was accomplished by determining the fuel cycle results for remote natural gas, residual oil, and diesel. The energy inputs for each of these "primary" fuels is illustrated in Table C-12. The full fuel cycle results are also indicated. The full fuel cycle includes the second order fuel cycle energy inputs associated with producing the primary fuels.

Natural gas extraction and transport energy is included in the fuel cycle for remote natural gas. Gas processing requirements for FTD feedstock differ from natural gas for utility and CNG usage where $CO_2$, LPG, and higher hydrocarbons are removed. These components can be included in the reformer feed and actually improve the efficiency of synthetic fuel production. Additional $CO_2$ and non methane hydrocarbons result in a synthesis gas with higher CO content than that produced with a pure methane reformer feed. The additional CO enables a higher conversion to product fuel and somewhat greater efficiency. Gas processing requirements for FTD and methanol production are lower than those for LNG or utility natural gas production (Dolan, Van Dyke).

The efficiency of the FTD facility has the most significant impact on fuel cycle energy and GHG emissions. An efficiency of 61 percent, HHV (63 percent LHV) was assumed. The efficiency depends on the plant configuration, which varies with each potential location and facility. Parameters such as production technology, feedstock costs, construction costs affect the configuration of the plant.

**Table C-12: FTD from Natural Gas-Production and Distribution Phases**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction, processing | Compressors | 0% ROW |
| 2 | Transport | Natural gas pipeline | 0% ROW |
| 3 | Production | FTD plant, combustion, vent | 10% ROW |
| 4 | Site storage | Fixed roof tanks | 20% ROW |
| 5 | Transport to bulk storage | Tanker ships | 26 kn SC, 26 kn ROW |
| 6 | Bulk storage | Floating roof tanks | SC |
| 7 | Transport to local station | Tanker trucks | 50 mi SC |
| 8 | Local station distribution | Underground tanks, refueling vapors and spillage | SC |

| Process | J/J | Input Fuels | Feedstock | | Energy Calculations |
|---|---|---|---|---|---|
| 1 Extraction | *0.0256* | | | | |
| 2 Processing, transport | *0.0101* | **RNG** | **RNG** | | *GREET 1.6 RNG SYNF* |
| 3 FTD plant | 1.587 | **RNG** | | | **NG No Compression** |
| 4 Site storage | | | | | Energy |
| 5 Marine tansport | 0.0109 | **Resid. Oil** | | | Loss |
| 6 Bulk storage | | | **FTD** | | *GREET 1.6 ROW* |
| 7 Transport to local station | 0.0013 | **ULSD** | | Product | **Residual Oil** |
| 8 Tank, fueling dispenser | 0.00018 | | | Loss | **ULSD, 10 ppm S** |
| **Fuel and Vehicle Cycle** | **1.667** | | **60.0%** | | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.5%. Extraction energy input is 0.0256J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery losses are 0.35%.
2. Processing efficiency is assumed to be 99%. This value is estimated based on the lower $CO_2$ and higher hydrocarbon removal requirements for syngas plants. Transport distance is 200 mile based on FTD plants associated with a dedicated remote gas resource. Gas processing and transport contribute 0.0101 J/J FTD plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for RNG. Natural gas processing losses are assumed to be 0.05% compared with 0.15% for pipeline gas because of the shorter transportation distances and limited $CO_2$ removal requirements associated with dedicated syngas projects
3. FTD plant requires 1.587 J of RNG feedstock per J of FTD product based on a 63%, LHV plant efficiency (61.1% HHV). GHG emissions for FTD production are 1.587 x RNG fuel cycle GHG x 1.00018, where 1.00018 is the product loss factor over the fuel cycle plus GHG emissions from the FTD plant. $CO_2$ emissions from the FTD plant = 44/12 x (1.587 x carbon in RNG – carbon in FTD) – 44/16 x $CH_4$ – 44/28 x CO. $CH_4$ and CO emissions are from syngas combustion and are lower than those for conventional natural gas combustion. 10% of plant emissions are assumed to occur in urban areas which is the GREET baseline value.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of plant emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. 150,000 DWT vessels transport methanol to California. 5400 kn was assumed for transport distance. Smaller vessels might be used but these would more likely be used over shorter distances. Energy and GHG emissions = 0.0109 x (fuel cycle + fuel combustion) for residual oil. These primary fuel results are calculated using GREET for overseas oil production. Urban emissions are calculated for 26 kn of travel in the SoCAB and at the overseas port. In-port emissions are also included.
6. Storage emissions are calculated for floating roof tanks in the SoCAB.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. Energy and GHG emissions = 0.0013 x (fuel cycle + fuel combustion) for ULSD. Fuel cycle values are calculated using GREET for 10 ppm sulfur ULSD produced overseas.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

Efficiencies in the range of 61 to 63 percent, HHV can be expected with Shell's SMDS technology, where the synthesis gas is produced with partial oxidation and pure oxygen feed. Efficiencies closer to 55 percent, HHV are achieved with air blown systems; however additional waste heat can be recovered and exported from the plant as steam. This study does not analyze air blown or small-scale FTD technologies. Most fuel cycle studies show similar results for air-blown systems because of credits associated with "steam export". In principle, exported steam can be used in other industrial processes and potentially can displace fossil energy.

Export steam might displace natural gas-based or coal based power as well as steam for chemical processing plants or desalinization plants. The uses of export steam involve more questions of marginal energy uses than most steps in the fuel cycle. Baseline GREET inputs assume that export steam displaces natural gas energy inputs. The fuel cycle GHG emissions with these assumptions are similar to those for higher efficiency FTD processes.

FT diesel is likely compatible with existing dispensing equipment and vehicle fuel systems. However, fuel compatibility issues have not been widely documented. Some fuel compatibility problems were identified when low aromatics diesel fuels were introduced in California. These problems appeared to occur on older model diesel engines with a specific type of fuel system.

FT diesel fuel can be transported in conventional product tankers. Bulk storage, product blending, truck delivery, and local product dispensing can be accomplished with existing infrastructure. If pure FT diesel fuel is sold as a separate product, refueling stations will need to reallocate their inventory of local storage tanks or install additional storage and dispensing equipment. FT fuels will likely be blended to produce high cetane, low aromatic diesel before they are sold as pure clean fuel alternatives. The blending approach allows for a build up of production and bulk storage capacity. If a demand for pure FT fuels develops, the infrastructure will be in place.

### Methanol from Natural Gas

Most methanol in the world and all of the methanol used in California as a vehicle fuel is made from natural gas. The conversion steps are similar to those used to make synthetic diesel. The final syngas conversion step differs. The synthesis gas produced by the reformer reacts over a copper-nickel based catalyst at 260°C and 10 to 30 atm. Similar to FTD production, methanol synthesis benefits from additional $CO_2$ and hydrocarbons in the natural gas feedstock (Supp). A gas processing efficiency of 99 percent was assumed for preparing methanol feedstock, which is the same value assumed for RNG feedstock for FTD.

High-volume methanol usage for vehicle fuel would require more facilities worldwide and larger scale plants would be possible. The cost and energy inputs for different methanol production technologies based on steam reforming, combined partial oxidation was analyzed in the California Methanol Cost Study (Bechtel). Other studies review the energy input requirements for methanol production (Stratton, Supp).

Several producers of methanol from natural gas including Methanex, Celanese, and Dewitt, provided several million gallons of methanol per year for transit buses and M85 FFVs operating in California in the 1990s. Daimler Chrysler, GM, Georgetown University, and others are demonstrating fuel cell powered passenger cars and buses with on-board reformers. Other potential feedstocks include landfill gas, biomass, and coal. Several designs of small-scale methanol plants have been considered. The efficiency and emissions from these facilities is analyzed in the 2001 ARB fuel cycle study (Unnasch 2001). Biomass and coal gasification and even using sequestered $CO_2$ and solar hydrogen have been analyzed as methanol production pathways (Katofsky, Simbeck, and Unnasch 1991). A coal to methanol production facility is operating at the Eastman Chemical Company in Kingsport Tennessee (Air Products) and waste feedstocks materials are feedstocks for biomass facilities in Germany (SVC).

The steps for methanol production and distribution are shown in Table C-13. Sources of urban emissions and primary energy inputs are indicated. Fuel cycle energy and GHG emissions are calculated from the results for primary fuels RNG, residual oil, and ULSD. The energy inputs shown in Table C-13 combined with the fuel cycle and fuel GHG emissions determine the fuel cycle emissions for methanol. The analysis is very similar to that of FTD with the primary differences reflected in the energy inputs for the methanol plant, marine vessel, and tanker truck. Since the energy density of methanol is roughly one-half that of petroleum fuels, the energy required for similar fuel transportation infrastructure and distances is twice that of petroleum fuels.

### LNG from Remote Natural Gas

LNG is produced from natural gas in liquefaction facilities. Natural gas is compressed and cooled and expanded in a multi stage operation. Energy for compression is usually provided with natural gas powered engines. LNG is stored as a cryogenic liquid in insulated storage vessels. The fuel is generally a liquid at its boiling point. When stored near atmospheric pressure the LNG temperature is -260°C. While LNG tanks are thermally insulated, some heat enters the tank, which results in the boil-off of liquid to gas. The pressure in the tank increases and after several days, the gas must be vented. The gas can be vented to the atmosphere, recovered as CNG, or burned to generate heat. LNG absorbs heat during transfer operations and some liquid is vaporized. Tank truck fuel transfer to a storage facility usually involves passing a small amount of LNG into a heat exchanger to generate gaseous natural gas. This process increases the pressure in the tank truck and forces the liquid into the receiver tank. After transferring the vapors, the gas on the truck is purged.

**Table C-13: Methanol from Natural Gas-Production and Distribution Phases**

| | Process | Emission Sources | California Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Compressors | 0% ROW |
| 2 | Transport | Natural gas pipeline (compressors & fugitive) | 0% ROW |
| 3 | Production | Methanol plant, combustion, vent | 10% ROW |
| 4 | Site storage | Fixed roof tanks | 20% ROW |
| 5 | Transport to bulk storage | Tanker ships | 26 kn SC, 26 kn ROW |
| 6 | Bulk storage | Floating roof tanks | SC |
| 7 | Transport to local station | Tanker trucks | 50 mi SC |
| 8 | Local station distribution | Underground tanks, refueling vapors and spillage | SC |

| Process | J/J | Input Fuels | Feedstock | | Energy Calculations |
|---|---|---|---|---|---|
| 1 Extraction | *0.0256* | | | | |
| 2 Processing, transport | *0.0101* | **RNG** | **RNG** | | *GREET 1.6 RNG SYNF* |
| 3 Methanol Plant | 1.460 | **RNG** | | | **NG No Compression** |
| 4 Site storage | | | | Energy | |
| 5 Marine tanker transport | 0.024 | **Resid. Oil** | | Loss | |
| 6 Bulk storage | | | **M100** | | *GREET 1.6 ROW* |
| 7 Local truck transport | 0.0029 | **ULSD** | | Product | **Residual Oil** |
| 8 Tank, fueling dispenser | 0.00019 | | | Loss | **ULSD, 10 ppm S** |
| **Fuel and Vehicle Cycle** | **1.516** | | **66.0%** | | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.5%. Extraction energy input is 0.0256J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery losses are 0.35%.
2. Processing efficiency is assumed to be 99%. This value is estimated based on the lower $CO_2$ and higher hydrocarbon removal requirements for syngas plants. Transport distance is 200 mile based on FTD plants associated with a dedicated remote gas resource. Gas processing and transport contribute 0.0101 J/J FTD plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for RNG. Natural gas processing losses are assumed to be 0.05% compared with 0.15% for pipeline gas because of the shorter transportation distances and limited $CO_2$ removal requirements associated with dedicated syngas projects
3. The methanol plant requires 1.460 J of RNG feedstock per J of methanol product based on a 68.5%, LHV plant efficiency (70.5% HHV). Experience with new methanol plants making chemical grade fuel shows efficiencies ranging from 66 to 70%, HHV depending on economic and site specific parameters. Efficiencies of 70.5% and higher, for large-scale fuel grade methanol containing up to 1% water are achievable (Stratton). GHG emissions for FTD production are 1.47 x RNG fuel cycle GHG x 1.00019, where 1.00019 is the product loss factor over the fuel cycle plus GHG emissions from the methanol plant. $CO_2$ emissions from the methanol plant = 44/12 x (1.46 x carbon in RNG – carbon in M100) – 44/16 x $CH_4$ – 44/28 x CO. $CH_4$ and CO emissions are from syngas combustion and are lower than those for conventional natural gas combustion. 10% of plant emissions are assumed to occur in urban areas which is the GREET baseline value.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of plant emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. 150,000 DWT vessels transport methanol to California. 5400 kn was assumed for transport distance. Smaller vessels might be used but these would more likely be used over shorter distances. Energy and GHG emissions = 0.024 x (fuel cycle + fuel combustion) for residual oil. These primary fuel results are calculated using GREET for overseas oil production. Urban emissions are calculated for 26 kn of travel in the SoCAB and at the overseas port. In-port emissions are also included.
6. Storage emissions are calculated for floating roof tanks in the SoCAB.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. Energy and GHG emissions = 0.0029 x (fuel cycle + fuel combustion) for ULSD. Fuel cycle values are calculated using GREET for 10 ppm sulfur ULSD produced overseas.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery. M100 spillage losses are zero based on zero drip nozzle developed to avoid human contact during fueling. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

The analysis of LNG from RNG was based on fuel production overseas and transport to a future marine terminal in the SoCAB. An LNG terminal could also be built in Mexico where the fuel could be distributed by rail to Southern California. The SoCAB emission results would be similar to those for LNG from domestic natural gas. Since no clear plan exists for the production of an LNG facility, the analysis was based on a new LNG terminal in the SoCAB. While this scenario is remote, the comparison of emissions with domestic or North American LNG is more revealing than a scenario where LNG is imported to Mexico and transported by rail to the SoCAB as many of the local distribution steps would be the same as LNG from domestic natural gas (Section C.4.2.2).

LNG is delivered to several areas of the world where it is primarily converted to pipeline gas or used in petrochemical industries. LNG terminals in the U.S. are located in Boston Massachusetts and Port Charles Louisiana. LNG is the primary source of pipeline natural gas in Japan.

The energy inputs associated with LNG production from remote natural gas are illustrated in Table C-14. Energy inputs for each step in the fuel cycle and the location of emissions are indicated. These values represent the efficiencies of each production step, rather than the fuel cycle energy input.

Important parameters in the LNG fuel cycle are the energy requirements for liquefaction. Liquefaction requirements are about 0.09 J/J of mechanical energy. For remote LNG plants, natural gas engines will provide the power. When the natural gas required for liquefaction is taken into account, this energy requirement is 0.225 J RNG/J LNG. Another important factor in the LNG fuel cycle is boil off losses from bulk storage and transport. Heat passes through the cryogenic tank insulation, which raises the temperature and pressure of the LNG. Removing either LNG product or vapor from the tank will reduce the pressure. Removing LNG vapor from the top of the tank reduces the pressure as the remaining liquid will boil and reduce the temperature of the tank contents. Boil off losses are either vented where they result in $CH_4$ emissions or are captured and used as fuel. In either case, additional LNG must be produced at the liquefier to make up for the boil off losses.

In most steps of the LNG fuel cycle, either using the fuel quickly or removing vapor from the tank can control boil off losses. Such gas recovery steps were assumed in all steps of the fuel cycle even though many boil off losses are not recovered today. The following uses of LNG are assumed:

- Recover boil off vapor from bulk tanks and use as fuel for liquefier compressors or compress and use as pipeline gas in California
- Use LNG vapor for marine vessel fuel when hauling LNG. Vessel operates on residual oil for back haul.

**Table C-14: LNG from Remote Natural Gas-Production and Distribution Phases**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Compressors | 0% ROW |
| 2 | Transport | Natural gas pipeline engines, losses | 0% ROW |
| 3 | Production | Liquefier, natural gas engines | 10% ROW |
| 4 | Site storage | Cryogenic tank | 10% ROW |
| 5 | Transport to bulk storage | Tanker ship | 26 kn SC, 26 kn ROW |
| 6 | Bulk storage | Cryogenic tank | SC |
| 7 | Transport to local station | Tanker truck | 50 mi SC |
| 8 | Local station distribution | Cryogenic tank, refueling vapors and spillage | SC |

| Process | J/J | Input Fuels | Feedstock | | Energy Calculations |
|---|---|---|---|---|---|
| 1 Extraction | 0.0256 | | | | |
| 2 Processing, Transport | 0.0257 | RNG | RNG | | *GREET 1.6 RNG LNG* |
| 3 Gas processing, liquefaction | 1.233 | RNG | | | **LNG** |
| 4 Site storage | 0.0005 | | | Energy | |
| 5 Marine tanker tansport | 0.0138 | LNG, Resid. | | Loss | |
| 6 Bulk storage | 0.0012 | | LNG | | |
| 7 Transport to local station | 0.0016 | LNG | | Product | |
| 8 Cyrogenic tank, fuel dispenser | 0.00665 | | | Loss | |
| **Fuel and Vehicle Cycle** | **1.318** | | **75.9%** | | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.5%. Extraction energy input is 0.0256J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery losses are 0.35%.
2. Gas processing efficiency is xxx 97.5%. Transport distance is 400 mile based on FTD plants associated with a dedicated remote gas resource. Gas processing and transport contribute 0.0257 J/J LNG plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Natural gas processing losses are 0.15%.
3. Liquefaction requires xxxx kJ/kg of LNG, which represents 1.xx x the energy required for vaporization. The power requirement expressed as a fraction of LNG product is 0.99 J power/J LNG or 91% efficiency. With RNG being the source of the power and 42.5% efficient (LHV) natural gas engines, the liquefaction energy input is 0.223 J RNG/ J LNG (LHV). 10% of plant emissions are assumed to occur in urban areas which is the GREET baseline value.
4. Bulk storage emissions are LNG vapor losses. Recovery of 90% of the boil off was assumed because of the desire to limit CH4 emissions. This boil off gas would be used as fuel for the liquefier. The total fuel cycle losses are combined in on value in step 8. 10% of storage tank emissions are assumed to occur in urban areas. The storage tanks would be in the same location as the liquefier.
5. 150,000 DWT vessels were assumed to transport LNG to California. LNG tanker operates on LNG and recovers 95% of boil off. Residual oil is used for the return trip. 5400 kn was estimated as the transport distance with South America and Malaysia being candidate locations for LNG facilities that would supply California. Urban emissions are calculated for 26 kn of travel in the SoCAB and at the overseas port. In-port emissions are also included.
6. Storage emissions are calculated for an LNG facility in the SoCAB. Recovery of 90% of boil off vapors is assumed for other industrial uses. If the facility were outside the SoCAB, additional local transport would be required.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. LNG trucks are used to haul fuel and this LNG is included in the LNG fuel cycle (referred to as “own use” in Wang 1999). Today’s LNG tanks often vent 5 atm tank contents after delivering fuel. For future LNG applications, 95 % of this vapor was assumed to be recovered as truck fuel.
8. Local fueling station emissions include losses from tank truck hose disconnect, storage tank venting, and vehicle nozzle disconnect. Today, some LNG vehicles must be vented when the saturation conditions in the vehicle tank prevent liquid product from filling the tank. Improved fueling methods were assumed for future LNG vehicle fueling. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

- For local stations, either recover boil off and compress for CNG or pipeline gas or use innovative vapor management techniques (Dehne)

- When tank trucks deliver LNG, the empty tank (holding about 60 psig) may be vented to prevent remaining LNG from boiling and raising pressure. Assume that the gas can be used as truck fuel.

#### C.4.2.2 Fuels from North American Natural Gas

**Compressed Natural Gas (CNG)**

Natural gas is available throughout most of California for home heating and industrial energy uses. CNG is used in several vehicle applications. In most CNG fueling facilities, electric motors power compressors, which compress pipeline gas. Several fuel storage and dispensing strategies are used. These approaches differ with the type of vehicle application, fuel throughput, and other requirements. The infrastructure for the extraction, processing, and distribution of natural gas is available for most potential CNG users where a compression facility might be installed.

Table C-15 shows the parameters for CNG production and distribution. The types of emissions sources for each step and the assumptions for the location of urban emissions and energy inputs are indicated. Several factors that affect the energy inputs for CNG include the distance the natural gas is transported, energy consumption for distribution compressor engines, and energy required to compress CNG for dispensing.

Future projections of gas resources in the U.S. indicate that supplies are limited and that additional gas will need to be imported. Marginal gas resources include pipeline from Canada or Alaska or LNG imports by marine vessel. The gas transmission distance was assumed to be 2000 mi. This relatively long distance reflects an assumption that the marginal gas production will come from outside the U.S.

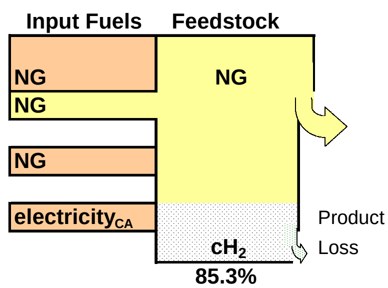
The energy inputs for compression vary with the fueling strategy as well as the type of equipment. A compressor energy of 0.9 kWh/kg was estimated for future CNG systems. (See discussion of compression energy requirements in Section C.6.3)

Fuel cycle energy inputs were calculated using GREET. Electric energy inputs for compression are based on natural gas power. This same marginal power assumption applies to compression energy for hydrogen, electricity for battery EVs, electrolysis for hydrogen production, and other electricity inputs in California.

**Table C-15: CNG – Production and Distribution Phases**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Compressors | 0% ROW |
| 2 | Transport | Natural gas pipeline compressor | 0% ROW |
| 3 | Refining | Gas sweetening, vent | 10% ROW |
| 4 | Site Storage | None | 20% ROW |
| 5 | Transport to bulk storage | Pipeline engines | 70 mi SC, 70 mi CA |
| 6 | Bulk storage | Underground storage | SC |
| 7 | Transport to local station | Pipeline enignes | Included in 5 |
| 8 | Local station compression reforming | Refueling losses, electric power for compression | SC |

| Process | J/J |
|---|---|
| 1 Extraction | *0.0267* |
| 2 Transport | *0.013* |
| 3 Gas processing | *1.022* |
| 5 Transmission pipeline | *0.02* |
| 6 Underground storage | |
| 7 CNG compressor | 0.031 |
| 8 Tank, fueling dispensor | 0.00009 |
| **Total Fuel Cycle** | **1.172** |




**Energy Calculations**

*GREET 1.6 CA*

**NG No Compression**

**Electric Power**

Energy

Loss

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.4%, which is the baseline, GREET value for North American gas. Extraction energy input is 0.015J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery losses are 0.35%.

2. Gas processing facilities are in close proximity to gas wells so transport energy requirement is relatively low.

3. Processing efficiency is assumed to be 97.8%. Gas processing and transport contribute 0.022 J/J gas processing plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for natural gas. Natural gas processing losses are assumed to be 0.15% which is the baseline GREET value. Energy and GHG emissions = 1.00009 x (fuel cycle + fuel combustion) for natural gas. All of the losses in the fuel cycle except steps 7 and 8 are included in this value.

5. Assume pipeline transportation distance of 2000 mi for marginal natural gas.

6. Some natural gas is stored underground in the SoCAB.

8a. CNG compressors are powered by electricity, which facilitates permitting. Energy inputs correspond to 0.9 kWh/100scf. Energy and GHG emissions = 0.031 x fuel cycle for electric power generation. Local fueling station emissions hose connect losses.

8b. Dispenser disconnect loss estimated at 1 cc at 5,000 psi. Product losses from steps 4, 6, and 8 are combined to determine total natural gas required in Step 3.

### Liquefied Petroleum Gas (LPG) from Natural Gas

Natural gas liquids are another source of LPG in addition to the by-products of oil refining. Propane, butane and traces of other hydrocarbons are removed from natural before the gas enters transmission pipelines. Natural gas-based LPG is transported from gas processing facilities and imported to California by rail.

Locomotive emissions and LPG losses from distribution equipment are the largest source of local emissions. Table C-16 illustrates the steps associated with LPG production. Feedstock extraction is the same as that of natural gas. The gas processing facility separates LPG components from natural gas and separates these as a liquid product at approximately 10 atm. The LPG is then transported by railcar to California and distributed with trucks.

The local distribution steps for LPG from natural gas are similar to those for LPG from petroleum. The principal difference is transportation distance. Some LPG from refineries will be distributed directly from product terminals, which may eliminate some railcar transportation.

Venting losses with current LPG transfer equipment correspond to about 0.5 percent of the product. Improved control of LPG venting is assumed for both the petroleum and natural gas pathways analyzed in this study. This assumption has a major impact on NMOG emissions and also reduces the impact of product losses on energy inputs in the fuel cycle.

### Liquefied Natural Gas (LNG) from U.S. Natural Gas

Currently, almost all LNG used in vehicle demonstrations has been trucked from Wyoming. Liquefied methane is available from a facility near Sacramento but this resource has not been utilized frequently. The LNG from Wyoming is produced in a pressure let-down facility that requires little energy input for liquefaction. For large scale production the liquefier could be at a natural gas peak shaving facility or it could be built as a dedicated facility.

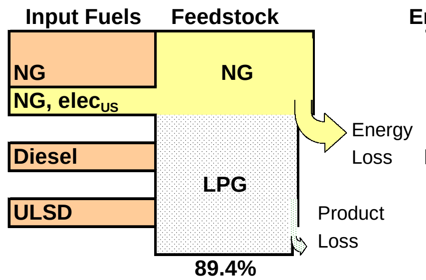
Several LNG liquefaction facilities have been considered in order to meet projected demand from LNG trucks and buses (Powars). A variety of production technologies including integration with pressure let down facilities, small scale liquefiers are possible options for future LNG supply.

The energy inputs for LNG production will depend on the integration with pipeline pressure requirements. Some LNG could produced from pressure let-down facilities and in-state production. The primary parameter that affects local emissions is the amount transportation distance.

**Table C-16: LPG from Natural Gas- Production and Distribution Phases**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Compressors | 0% US |
| 2 | Transport | Natural gas pipeline compressor | 0% US |
| 3 | Refining | Gas sweetening, vent | 10% US |
| 4 | Site Storage | None | 20% US |
| 5 | Transport to bulk storage | Pipeline engines | 70 mi SC, 70 mi CA |
| 6 | Bulk storage | Underground storage | SC |
| 7 | Transport to local station | Pipeline engines | 50 mi SC |
| 8 | Local station compression reforming | Refueling losses, electric power for compression | SC |

| Process | J/J | Energy Calculations |
|---|---|---|
| 1 Extraction | 0.0267 | |
| 3 Gas processing | 1.036 | *GREET 1.6 US* |
| 4 Site storage | | **LPG, NG** |
| 5 Transport to bulk storage | 0.03 | Diesel, 350 ppm S |
| 6 Bulk storage | 0.0007 | ULSD, 10 ppm S |
| 7 Local truck transport | 0.0015 | |
| 8 Tank, fueling dispensor | 0.0003 | |
| **Fuel and Vehicle Cycle** | **1.119** | |




[a] SC = emissions occuring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated

1. Natural gas extraction efficiency is 97.4% which is the baseline GREET value for North American gas. Extraction energy input is 0.015J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery losses are 0.35%.
2. Extraction efficiency is 97.5. Gas processing and transport contribute 0.0101 J/J FTD plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for RNG. Natural gas processing losses are 0.15%.
3. Gas processing efficiency is 99.9%.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of plant emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. LPG is hauled to California by railcar.
6. Bulk storage facilities release LPG from hose connect losses from loading and unloading. Bulk tanks also have outage valve losses. The outage valve losses were assumed to be 90% controlled in the future.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption.
8. Local fueling station emissions include hose disconnect losses for fuel transfer from delivery trucks and to the vehicle. Also, outage valve losses also occur on the vehicle and storage tanks. A 90% reduction in these emissions was assumed. Product losses from steps 4, 6, and 8 are combined to determine total ULSD required in Step 3.

Table C-17 shows the assumptions for LNG production and distribution from U.S. natural gas. Since pipeline gas is the feedstock, extraction and processing requirements are the same as those for CNG. Differences between CNG and LNG production arise from the resource transportation mode and the energy requirements for liquefaction.

Most of large-scale LNG distribution modes would involve rail transport so their local emissions impact would be similar. The energy input for natural gas extraction and liquefaction as well as the energy requirements for transportation affect GHG emissions. Energy requirements and associated GHG impacts for rail transport from the western states are similar to energy requirements for tanker ship transport from remote sources. This comparison can be seen in the discussion of GHG emissions and energy inputs. Another parameter that affects LNG production is the source of energy for liquefaction. As LNG is produced in a location where natural gas is plentiful, natural gas ICE engines are assumed to be the energy source for liquefaction.

### Hydrogen

Hydrogen can be produced from many feedstocks with different production pathways. The most common methods involve the conversion of hydrocarbons such as natural gas or the electrolysis of water. Several other feedstocks are possible including LPG, methanol, ethanol, biomass, and coal. Both large-scale central facilities with hydrogen transported to the fueling station and on-site production are possible. The delivery modes include compressed gas in tube trailers, liquefied hydrogen in trucks, pipelines, or on-site production. The various modes of hydrogen production and energy inputs are discussed in several detailed studies (Lasher, Simbeck, Thomas, Katofsky). An important difference in these studies is the level of development of conversion technologies. The values used in this study reflect long term assumptions and higher efficiencies that are expected with advancements in hydrogen production equipment.

Most hydrogen today is produced from fossil fuels. Methane, for example, is reformed into CO and hydrogen. The CO is reacted with steam to form additional hydrogen. Non fossil methods of hydrogen reduction include electrolysis of water, thermochemical splitting of water, and photolysis. Electrolysis separates water into hydrogen and oxygen by passing current through an electrochemical cell.

Three hydrogen production pathways were analyzed in this study, on-site reforming of natural gas, central plant natural gas reforming with liquid hydrogen delivery, and on-site electrolysis using grid power. These pathways represent different distribution modes and emission sources. The analysis is based on delivering compressed hydrogen gas to passenger cars at 5,000 psi (350 atm). The energy inputs for buses, which store hydrogen at 3,000 psi (200 atm) would be slightly lower. Liquid hydrogen LH2 delivered to local fueling stations can also be transferred to vehicles with on-board LH2 storage tanks. The energy inputs would be similar to those described for on-site LH2 storage and compressed hydrogen vehicle fueling. The energy consumption depends on the configuration of the LH2 fueling station.

**Table C-17: LNG from U.S. Natural Gas- Production and Distribution Phases**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Compressors, fugitive | 0% US |
| 2 | Transport | Pipeline (compressors and fugitive) | 0% US |
| 3 | Refining/Production | Fugitives, compressor engines, gas combustion | 10% US |
| 4 | Site Storage | On-site tanks | 20% US |
| 5 | Transport to bulk storage | Rail car (engines and fugitives) | 70 mi SC, 70 mi CA |
| 6 | Bulk storage | Cryogenic tank | SC |
| 7 | Transport to local station | Tanker trucks (engines and fugitive) | 50 mi SC |
| 8 | Local station distribution | Above grounds tanks, refueling vapors | SC |

| | Process | J/J | Input Fuels | Feedstock | | Energy Calculations |
|---|---|---|---|---|---|---|
| 1 | Extraction | *0.0267* | | | | *GREET 1.6 CA* |
| 2 | Processing, transport | *0.0225* | **NG** | **NG** | | **NG No Compressio** |
| 3 | Liquefaction at pipeline | 0.032 | **elec$_{CA}$** | | | **Electric Power** |
| | | 1.026 | **NG** | | | |
| 4 | Site storage | 0.0005 | | | Energy | |
| 5 | LNG rail car | 0.010 | **LNG** | | Loss | |
| 6 | Bulk storage | | | **LNG** | | *GREET 1.6 ROW* |
| 7 | Local truck transport | 0.0016 | **LNG** | | Product | **ULSD, 10 ppm S** |
| 8 | Tank, fueling dispenser | 0.00665 | | | Loss | |
| | **Fuel and Vehicle Cycle** | **1.202** | | **83.2%** | | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.4%, which is the baseline, GREET value for North American gas. Extraction energy input is 0.015J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery losses are 0.35%.
2. Processing efficiency is assumed to be 97.8%. Gas processing and transport contribute 0.022 J/J FTD plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for natural gas. Natural gas processing losses are assumed to be 0.15% which is the baseline GREET value. Energy and GHG emissions = 1.00009 x (fuel cycle + fuel combustion) for natural gas. All of the losses in the fuel cycle except steps 7 and 8 are included in this value. Transport to the pressure let down facility (2000 mi) is the primary energy input.
3. Liquefiers can be at pressure let down facilities or associated with stranded gas assets. For a liquefier that operates at a pressure let-down facility, the energy required for liquefaction was estimated at 0.5 kWh/100scf which is 0.018 J power/J LNG. A composite 0.032 J/JLNG was assumed which would include both pressure let down facilities and dedicated liquefiers.
4. Bulk storage emissions are LNG vapor losses. Recovery of 90% of the boil off was assumed because of the desire to limit CH4 emissions. This boil off gas would be used as fuel for the liquefier. The total fuel cycle losses are combined in on value in step 8. The storage tanks would be in the same location as the liquefier.
5. LNG powered locomotives are assumed to haul LNG to California. 95% of boil off is recovered
6. Storage emissions are calculated for an LNG facility in the SoCAB. Recovery of 90% of boil off vapors is assumed for other industrial uses. If the facility were outside the SoCAB, additional local transport would be required.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. LNG trucks are used to haul fuel and this LNG is included in the LNG fuel cycle (referred to as “own use” in Wang 1999). Today’s LNG tanks often vent 5 atm tank contents after delivering fuel. For future LNG applications, 95 % of this vapor was assumed to be recovered as truck fuel.
8. Local fueling station emissions include losses from tank truck hose disconnect, storage tank venting, and vehicle nozzle disconnect. Today, some LNG vehicles must be vented when the saturation conditions in the vehicle tank prevent liquid product from filling the tank. Improved fueling methods were assumed for future LNG vehicle fueling. Product losses from steps 4, 6, and 8 are combined to determine total pipeline gas required in Step 3.

### Hydrogen from Natural Gas

Table C-18 shows the production and distribution pathway for on-site hydrogen production from natural gas. The energy inputs and sources of emissions are indicated. The approach for calculating energy inputs and GHG emissions is similar to that of CNG. Energy inputs for hydrogen production at the local fueling station are combined with the fuel cycle for natural gas and electric power production and the carbon in natural gas.

The calculation of energy inputs and GHG emissions collapses to the simple multiplication of natural gas consumption by parameters for the fuel cycle and fuel plus similar calculations for power consumption. Details of this calculation are discussed in Section C.8. The shaded areas in Figure C-10 represent the energy inputs in the fuel cycle and hydrogen vehicle operation. The magnitude of the energy use corresponds approximately to impact on GHG emissions. While no GHG emissions are emitted from hydrogen fuel cell vehicle operation[25], all of the fuel cycle energy inputs and GHG emissions are proportional to vehicle fuel consumption.

The natural gas reformer consumes most of the energy in the fuel cycle. In Figure C-10, the reformer energy losses correspond to about 0.4 J/J of hydrogen product with 1 J of energy produced as the fuel. Most of the GHG emissions associated with the use of natural gas are emitted from the reformer (the total 1.4 J/J). Energy consumption for electric power generation corresponds to 0.24 J/J of hydrogen produced. This value includes the electricity itself and energy inputs for power generation (indicated as second order fuel cycle). Both the estimates for reformer and compressor energy consumption reflect optimized future systems.

Some strategies for hydrogen production could result in lower energy usage. The integrated production of hydrogen, fuel cell power, and heat could improve the economics of hydrogen production and also result in a further improvement in energy consumption.

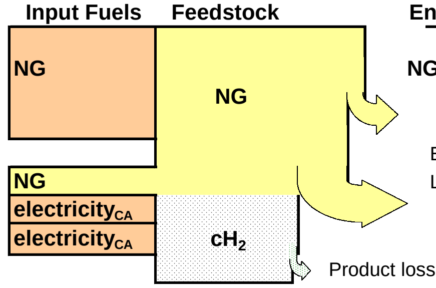
Other compressed hydrogen distribution options are also possible. These include transporting the hydrogen from production facilities to local storage and dispensing stations by tube trailers and pipeline transport. Hydrogen is currently available in tube trailers that carry 120,000 scf (300 kg) at 2,400 psi (163 atm). The hydrogen would be compressed to fill vehicle tanks at 5,000 psi. This option is currently feasible but not desirable over the long term since the amount of hydrogen energy contained in a tube trailer is lower than that of other fuels. Other means of distributing compressed hydrogen are possible but were not evaluated further.

[25] Hydrogen ICE vehicles would emit low levels of $N_2O$ which would represent less than 1% of GWP weighted fuel cycle GHG emissions.

**Table C-18: Hydrogen from Natural Gas – On-site Steam Reforming**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Compressors, fugitive | 0% US |
| 2 | Transport | Natural gas pipeline | 0% US |
| 3 | Refining | Fugitive emissions, vent gas combustion | 10% US |
| 4 | Site Storage | None | 20% US |
| 5 | Transport to bulk storage | Pipeline (pumps and fugitive) | 70 mi SC, 70 mi CA |
| 6 | Bulk storage | Underground storage | SC |
| 7 | Transport to local station | Pipeline (pumps and fugitive) | Included in 5 |
| 8 | Local station compression reforming | Refueling losses, electric power for compression, reformer emissions | SC |

| Process | J/J | Input Fuels | Feedstock | Energy Calculations |
|---|---|---|---|---|
| 1 Extraction | *0.0256* | | | *GREET 1.6 CA* |
| 3 Gas processing | *0.0225* | NG | NG | **NG Not Compressed** |
| 5 Pipeline transport | *0.0132* | | | **Electric Power** |
| 6 Underground storage | | | | |
| 8a Local reformer | 1.316 | NG | | |
| | 0.022 | electricity$_{CA}$ | | |
| 8b Compressor | 0.0791 | electricity$_{CA}$ | $cH_2$ | |
| 8c Dispenser | 0.00001 | | | |
| **Fuel and Vehicle Cycle** | **1.705** | | **58.7%** | |




[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.4%, which is the baseline, GREET value for North American gas. Extraction energy input is 0.015J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas. ROW urban emission shares (0%) are baseline GREET assumptions and used in this study. Natural gas recovery losses are 0.35%.

2. Gas processing facilities are in close proximity to gas wells so transport energy requirement is relatively low.

3. Processing efficiency is assumed to be 97.8%. Gas processing and transport contribute 0.022 J/J FTD plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for natural gas. Natural gas processing losses are assumed to be 0.15% which is the baseline GREET value. Energy and GHG emissions = 1.00009 x (fuel cycle + fuel combustion) for natural gas. All of the losses in the fuel cycle except steps 7 and 8 are included in this value.

5. Assume pipeline transportation distance of 2000 mi for marginal natural gas.

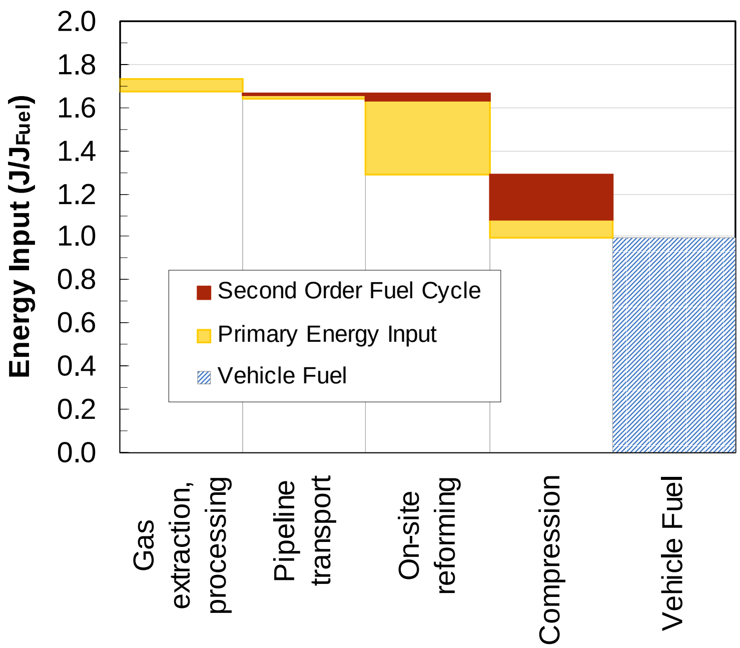
6. Some natural gas is stored underground in the SoCAB. The marginal emissions impact is assumed to be small.

8a. Energy inputs correspond to 0.166 MMBtu (HHV)/kg plus 2.63 kWh/kg electricity (Lasher 2002). Expressed in on an LHV basis, 1.316 J/J natural gas and 0.022 J/J electricity.

8b. Hydrogen compressors are powered by electricity, which facilitates code compliance, emission constraints, and permitting. Energy inputs correspond to 2.63 kWh/kg. Total Energy and GHG emissions for reforming and compression = 0.101 x fuel cycle for electric power generation + 1.316 x fuel cycle for natural gas + 1.316 x (44/12 x carbon in NG – 44/16 x $CH_4$ – 44/28 x CO from reformer emissions).

8c. Dispenser disconnect loss estimated at 1 cc at 5000 psi. Product losses combined to determine total natural gas required in Step 8.

**Figure C-10. Energy Losses from Hydrogen from Natural Gas – On-site Reformer**




Source: GREET 1.6 with fuel cycle assumptions in this study.

TIAX evaluated the energy inputs for a variety of hydrogen production pathways as part of a study for DOE (Lasher 2002). The results of this study can provide a further basis for assessing local emission impacts associated with hydrogen distribution. The on-site steam reformer pathway was selected because it is both versatile and relatively low cost. However, the cost effectiveness of hydrogen production options depends upon many parameters including feedstock price and the usage rate at the fueling facility.

Liquid hydrogen is another pathway for distributing hydrogen. The advantages of liquid hydrogen transport include production at a central facility and proven on-site storage infrastructure. The liquid hydrogen can be pumped to high pressure or first evaporated and then compressed to high pressure. Using a cryogenic pump requires less compression energy but causes hydrogen to boil off every time the pump is started.

Table C-19 shows the steps and energy inputs associated with hydrogen production with liquid hydrogen (LH2) delivery. LH2 delivery lends itself to applications that use several hundred kg of hydrogen per day. Using a significant fraction of the hydrogen can help manage boil off losses from LH2 storage.

**Table C-19: Hydrogen from Natural Gas – Central Reformer, Liquid Hydrogen**

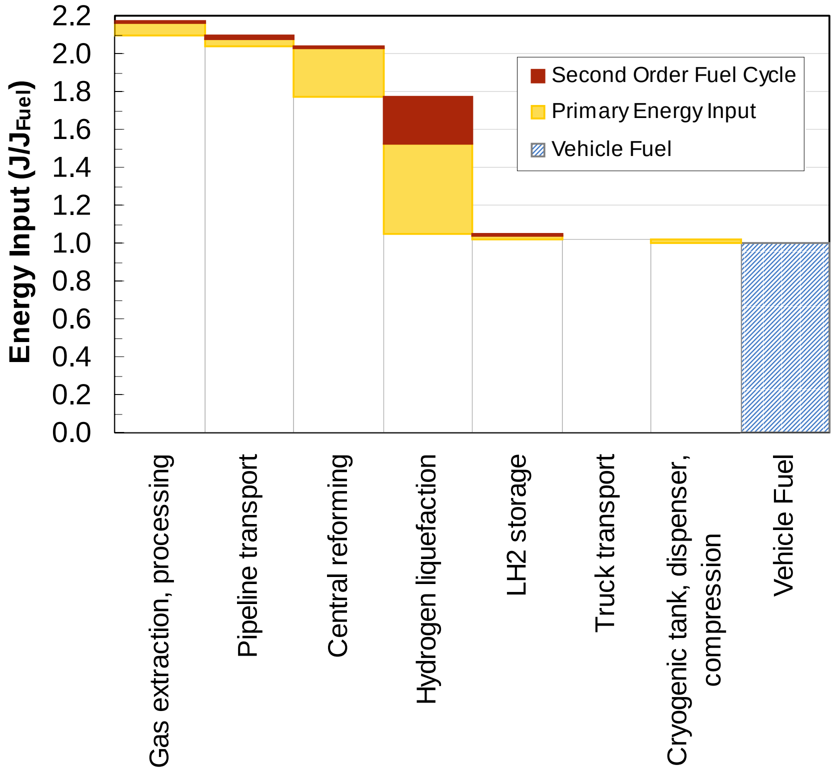
| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Compressors, gas processing | 5% US, 5% ROW |
| 2 | Transport | Natural gas pipeline | 70 mi SC, 70 mi CA |
| 3 | Refining | Fugitive emissions, vent gas combustion | SC |
| 4 | Site Storage | None | SC |
| 5 | Transport to bulk storage | Pipeline (pumps and fugitive) | SC |
| 6 | Bulk storage | Underground storage | SC |
| 7 | Transport to local station | Tank Truck | 50 mi SC |
| 8 | Storage, compression | Refueling losses, compressor | SC |

| Process | J/J | Input Fuels | Feedstock | Energy Calculations |
|---|---|---|---|---|
| 1 Extraction | *0.027* | | | *GREET 1.6 CA* |
| 1b Gas processing | *0.022* | NG | NG | **NG No Compression** |
| 2 Pipeline transport | *0.013* | | | **Electric Power** |
| 3a Central reformer | 1.26 | NG | | |
| 5a Hydrogen liquefier | 0.344 | NG | | Energy |
| 5b Hydrogen liquefier | 0.138 | electricity$_{CA}$ | | Losses |
| 6 Bulk cryogenic storage | 0.02 | | $LH_2$ | *GREET 1.6 ROW* |
| 7 Local truck transport | 0.0023 | ULSD | | **ULSD, 10 ppm S** |
| 8 Cyrogenic tank, fuel dispenser | 0.02 | | $cH_2$ | Product loss |
| **Fuel and Vehicle Cycle** | **2.174** | | **46.0%** | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.5%. GREET assumptions, used in this study are 0% of the criteria pollutant emissions in urban areas. ROW urban emission estimates are baseline GREET assumptions and used in this study. Expressed as fuel cycle energy, extraction is 0.0256J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas.
2. Extraction efficiency is 97.5%. This value is estimated based on the lower $CO_2$ and higher hydrocarbon removal requirements for syngas plants. Transport distance is 200 mile based on FTD plants associated with a dedicated remote gas resource. Gas processing and transport contribute 0.0101 J/J FTD plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for RNG. Natural gas processing losses are assumed to be 0.1% compared with 0.35% because of the shorter transportation distances and no under ground storage associated with dedicated syngas projects.
3. Assume central plant efficiency is 79.3% LHV(Contadini).
5. Liquefier power requirement is 0.27 J/J LH2. Assume that half of the mechanical power is generated on-site with natural gas engines..
6. Losses from bulk storage due to boil off.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. Energy and GHG emissions = 0.0013 x (fuel cycle + fuel combustion) for ULSD. Fuel cycle values are calculated using GREET for 10 ppm sulfur ULSD produced overseas.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

**Figure C-11: Energy Losses from Hydrogen from Natural Gas – Central Reformer, Liquid Transport**




Source: Based on fuel cycle results for primary energy inputs from GREET

### C.4.3 Biomass Fuels

#### Ethanol

A variety of materials are potential feedstocks for ethanol production. These include sugars and starches from agricultural products, petrochemicals, and cellulose from biomass materials. Both starches and cellulose can be converted to sugars and fermented to produce $CO_2$ and ethanol. Ethanol from petrochemical feedstocks is not evaluated in this study because this product is rarely used as a vehicle fuel[26].

Starch and sugar feedstocks comprise most of the global ethanol production capacity. These feedstocks are primarily corn, sugar beets, and sugar cane. Other grains and waste sugar feedstocks are also used for ethanol production on a smaller scale. Almost all of the ethanol blended with gasoline in the U.S. is derived from corn. Brazil

With cellulose feedstocks, ethanol is produced from the hydrolysis and fermentation of the feedstock. The biomass feedstock is assumed to be wood materials, either from forest, agricultural or possibly municipal residues. Ethanol from these woody feedstocks is a long-term option for production in California. Starch-based ethanol from corn is currently in production and would mostly likely be imported into the state from the Mid-west by rail or marine vessel. For California biomass ethanol production, a 2000 Energy Commission study of Costs and Benefits of a Biomass-to-Ethanol Production Industry in California found three main elements of the industry: biomass handling (harvesting, processing, storage, and transportation), production of ethanol, and transportation of ethanol.

#### Ethanol from Corn

Table C-20 shows the energy inputs and steps associated with ethanol production from corn. Values are based on GREET inputs. Main assumptions that affect GHG emissions are agricultural energy inputs, production yields, and requirements for processing. Assumptions in this study are 2.65 gal/bu for ethanol production yield and 38,000 Btu/gal (LHV) energy input for the ethanol plant. Transportation inputs are based on waterway and railcar from the Midwest.

The 5.7 percent blend is California's formulation used to meet a 2 percent by weight federal oxygenate requirement in Phase 3 gasoline. This formulation will be the primary demand for ethanol fuel in California. Additionally, ethanol is used in other motor fuel applications, such as E85 for flexible fuel vehicles, E100 for demonstration in modified heavy-duty fleets or fuel cell-powered vehicles, and Oxydiesel, a blend of 80 percent diesel, 10 percent ethanol, and 10 percent additives and blending agents. The Oxydiesel is also being demonstrated in bus fleets with unmodified diesel engines.

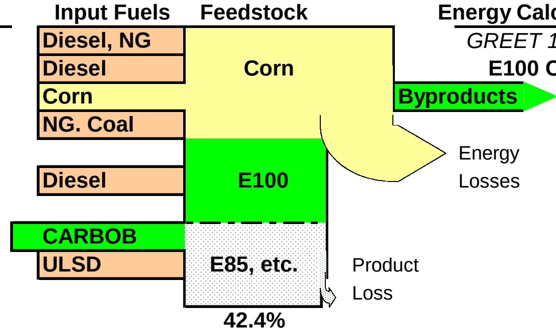
[26] Only ethanol derived from biomass feedstocks is eligible for the Federal tax credit for ethanol or ethanol blends.

**Table C-20: Production and Distribution Phases for Ethanol from Corn**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Agricultural equipment | 0% US |
| 2 | Transport | Truck (engine) | 0% US |
| 3 | Refining/Production | Fugitives, gas combustion | 10% US |
| 4 | Site Storage | On-site tanks | 20% US |
| 5 | Transport to bulk storage | Rail car (engines and fugitives) | 70 mi SC, 70 mi CA |
| 6 | Bulk storage | Floating roof tank (ethanol), blend with gasoline | SC |
| 7 | Transport to local station | Tanker trucks (engines and fugitive) | 50 mi SC |
| 8 | Local station distribution | Above grounds tanks, refueling vapors | SC |

| Process | J/J |
|---|---|
| 1 Farming, fertilizer production | |
| 2 Transport | |
| 3 Ethanol Plant | 1.4 |
| | 0.447 |
| 4 Site Storage | |
| 5 Marine Vessel/ Rail Car | 0.04 |
| 6 Bulk storage | |
| 6b Blending component | |
| 7 Local truck transport | **0.0014** |
| 8 Tank, fueling dispensor | |
| **Fuel and Vehicle Cycle** | **2.356** |

**Input Fuels** **Feedstock**




**Energy Calculations**

*GREET 1.6 US*

**E100 Corn**

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Farming energy input assumptions are same as GREET baseline values. Natural gas extraction efficiency is 97.5%. Coal extraction energy is 0.03 J/J. GREET assumptions, used in this study are 0% of the criteria pollutant emissions in urban areas.
2. Feedstock assumptions the same as baseline GREET values.
3. Energy inputs for the ethanol plant are 38,000 Btu (LHV)/gal. A 50/50% split is assumed between coal and natural gas. Ethanol production yield is 2.65 gal/bushel. 40 % of energy inputs are allocated to byproducts which is the same as the GREET baseline value.
4. Bulk storage emissions are NMOG vapor losses. The total fuel cycle losses are combined in on value in step 8. 20% of plant emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. Assume marine vessel transport by barge down Mississippi, then 150,000 DWT tanker to California. Assume 50% is transported by railcar.
6. Storage emissions are calculated for floating roof tanks in the SoCAB.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. Energy and GHG emissions = 0.0014 x (fuel cycle + fuel combustion) for ULSD. Fuel cycle values are calculated using GREET for 10 ppm sulfur ULSD produced overseas.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

Ethanol in the U.S. is used in several markets (Perez 2001) which affects the supply available to California. In 2001, most ethanol was used in a 10 percent blend with gasoline. This is traditionally referred to as gasohol, a term that is being replaced with ethanol/gasoline blend or E10. Lower percentage blends, containing 5.7 percent of 7.7 percent ethanol are also being used in some areas to conform to air quality regulations affecting the oxygen content of reformulated gasoline.

In addition to production from corn in the Midwest, several starch-based feedstocks have been considered for production facilities in California. A modest amount of ethanol is produced from sugar wastes such as soft drink syrup, candy, unused sugar containing or alcoholic beverages.

In this analysis, neither cellulosic nor starch based ethanol are produced in the SoCAB, resulting in no local fuel cycle emissions in the region except for transportation of the fuel. Greenhouse gas emissions from the different feedstocks, however, are completely accounted for since GHGs are measured globally rather than locally.

### Ethanol from Cellulose

Several cellulose-based ethanol production options have been considered for large scale production facilities in California. All of these processes would convert cellulose to sugars followed by fermentation to ethanol.

Several pathways are also possible. Each was analyzed in the CEC biomass to ethanol study. Energy inputs for a variety of processes were modeled and reported in Perez 1999. Most of these options resulted in very low or reduced net criteria pollutant emissions (Perez 2001). In order to simplify the analysis in this study, the net emissions for biomass ethanol production outside of the SoCAB were set to zero so the only criteria pollutant emissions shown here are those associated with transportation in the SoCAB. The details of emission reductions in rural California were not shown here because analyzing the locations where emissions would occur and population exposures was not in the study scope. The cellulose-based pathway is presented here in order to assess GHG emissions and criteria pollutants in urban areas.

Table C-21 shows the energy inputs and steps associated with ethanol production from biomass. The analysis here is based on processing forest residue. The energy inputs are diesel for feedstock collection. The ethanol plant also produces lignin as a co-product, which is used to generate electric power.

Many of the cellulose-based pathways resulted in emission reductions. Forest material could potential be removed from overgrown areas to reduce the risk of wildfires. The reduced risk and fuel reduction would eliminate future emissions from wildfires. With agricultural residue, burning of crops was avoided.

**Table C-21: Ethanol from Biomass, Forest Material**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Skidder, chipper, other diesel equipment | 0% US |
| 2 | Transport | Truck | 0% US |
| 3 | Refining/Production | Fugitives, gas combustion | 10% US |
| 4 | Site Storage | On-site tanks | 20% US |
| 5 | Transport to bulk storage | Rail car | 70 mi SC, 70 mi CA |
| 6 | Bulk storage | Floating roof tank (ethanol), blend with gasoline | SC |
| 7 | Transport to local station | Tanker trucks | 50 mi SC |
| 8 | Local station distribution | Above grounds tanks, refueling vapors | SC |

| Process | J/J | Input Fuels | Feedstock | Energy Calculations |
|---|---|---|---|---|
| 1 Farming, fertilizer production | | | Forest | *GREET 1.6 ROW* |
| 2 Transport | 0.03 | Diesel | Material | **ULSD, 10 ppm S** |
| 3 Ethanol Plant | 0.001 | Diesel | | Lignin |
| | 1.35 | Wood Chips | | |
| 5 Rail Car | 0.01 | Diesel | E100 | Energy |
| 6 Bulk storage | | | | Losses |
| 6b Blending component | | CARBOB | | |
| 7 Local truck transport | 0.0020 | ULSD | E85, etc. | Product |
| 8 Tank, fueling dispensor | | | | Loss |
| **Fuel and Vehicle Cycle** | **1.538** | | **65.0%** | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. This scenario is based on recovering forest material for fuel reduction to avoid forest fire risk (Perez 2001). The principal energy input is diesel for tree removal and chipping equipment.
2. Extraction efficiency is 97.5%. This value is estimated based on the lower $CO_2$ and higher hydrocarbon removal requirements for syngas plants. Transport distance is 200 mile based on FTD plants associated with a dedicated remote gas resource. Gas processing and transport contribute 0.0101 J/J FTD plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for RNG. Natural gas processing losses are assumed to be 0.1% compared with 0.35% because of the shorter transportation distances and no under ground storage associated with dedicated syngas projects.
3. The methanol plant requires 1.460 J of RNG feedstock per J of methanol product based on a 68.5%, LHV plant efficiency (70.5% HHV). natural gas combustion. 10% of plant emissions are assumed to occur in urban areas which is the GREET baseline value.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of plant emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. xxx.
6. Storage emissions are calculated for floating roof tanks in the SoCAB.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. Energy and GHG emissions = 0.0013 x (fuel cycle + fuel combustion) for ULSD. Fuel cycle values are calculated using GREET for 10 ppm sulfur ULSD produced overseas.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery. M100 spillage losses are zero based on zero drip nozzle developed to avoid human contact during fueling. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

With urban waste, landfilling and related emissions are avoided. However, a natural gas boiler would be required to power the ethanol plant. The urban waste scenario was the only one with significant fossil fuel input. Energy crops were discussed in the CEC study but not analyzed because the other alternatives appeared to have a greater potential for near term commercialization due to lower feedstock costs

### Biodiesel

Table C-22 shows the steps and energy inputs associated with biodiesel production. The analysis uses GREET baseline values except transportation distances reflect railcar transport to California

The scenario represents soybean farming and processing to soybean oil. By products represent a substantial fraction of the energy associated with soybean farming. The soybean oil is processed with methanol to produce an ester which is more stable for storage. Biodiesel is blended with ULSD at either a 2 or 20 percent level.

All of the biofuel production pathways presented in this study involve allocations of energy inputs to co-products. The co-product allocation results in the different results for ethanol produced from corn versus biodiesel. The fossil energy inputs for cellulose based ethanol production are very low so the allocation to co-products has less of an impact on the GHG emission results.

**Table C-22: Biodiesel from Soybean Oil**

| | Process | Emission Sources | Urban Emissions[a] |
|---|---|---|---|
| 1 | Extraction | Agricultural equipment | 0% US |
| 2 | Transport | Truck (engine) | 0% US |
| 3 | Refining/Production | Fugitives, gas combustion | 10% US |
| 4 | Site Storage | On-site tanks | 20% US |
| 5 | Transport to bulk storage | Rail car | 70 mi SC, 70 mi CA |
| 6 | Bulk storage | Floating roof tank (ethanol), blend with gasoline | SC |
| 7 | Transport to local station | Tanker trucks (engines and fugitive) | 50 mi SC |
| 8 | Local station distribution | Above grounds tanks, refueling vapors | SC |

| | Process | J/J | Input Fuels | Feedstock | Energy Calculations |
|---|---|---|---|---|---|
| 1 | Farming, fertilizer production | | **Diesel, NG** | | *GREET 1.6 US* |
| 2 | Transport | 0.03 | **Diesel** | **Soybeans** | **Biodiesel100** |
| 3 | Esterification | 0.1 | **Methanol** | | |
| 3 | Processing Plant | 0.9 | **Soybean Oil** | | |
| 5 | Rail Car | 0.02 | **Diesel** | **Biodiesel** | Energy |
| 6 | Bulk storage | | | | Losses |
| 6b | Blending component | | **ULSD** | | |
| 7 | Local truck transport | 0.0014 | **ULSD** | **BD20, etc.** | Product |
| 8 | Tank, fueling dispensor | | | | Loss |
| | **Fuel and Vehicle Cycle** | **1.375** | | **72.7%** | |

[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. About 60 percent of energy inputs are allocated to co-products. GREET assumptions, used in this study are 0% of the criteria pollutant emissions in urban areas. U.S. urban emission estimates are baseline GREET assumptions and used in this study.
2. Soybeans are transported to processing facilities by railcar.
3. Biodiesel processing is processed from soybean oil.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of plant emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
5. 1200 mi railcar transport from the Midwest.
6. Storage emissions are calculated for floating roof tanks in the SoCAB.
7. Tanker trucks travel distance is 50 mi in the SoCAB. The truck meets ARB 2007 emission standards and delivers a full load of fuel. Partial loads and shorter trips would lead to similar energy consumption. Energy and GHG emissions = 0.0014 x (fuel cycle + fuel combustion) for ULSD. Fuel cycle values are calculated using GREET for 10 ppm sulfur ULSD produced overseas.
8. Local fueling station emissions include vapor losses for fuel transfer from delivery. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

### C.4.4 Power Generation

Electricity in California is used in many of the fuels' fuel cycle phases including electric pumps and motor. It can also be used in the fuel cycle process for powering electric vehicles and electrolysis for fuel cell vehicles operating on hydrogen. The emissions associated with these fuel cycles are entirely associated with the fuel feedstocks and the efficiency of the conversions.

#### C.4.4.1 Power Generation Resources

The emissions associated with electricity generation have been documented in other studies (Unnasch 2001). The 2001 ARB study found that modeling power generation and source mix is complex because current generation statistics have little bearing on marginal power generation. Electricity in California is currently generated from a mix of natural gas, hydroelectric power, coal, nuclear power, biomass, and other renewables. The electricity is produced both in and outside of California.

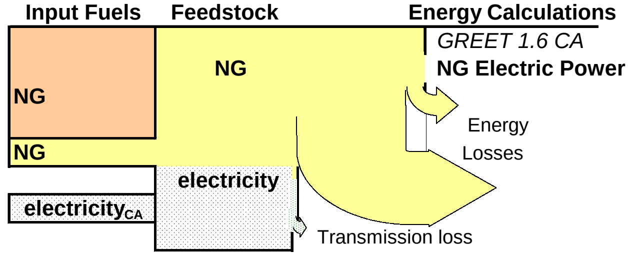
There may be marginal emissions in the SoCAB due to gas-fired power plants but the $NO_x$ emissions will be zero due to RECLAIM constraints. CO and NMOG are not governed by RECLAIM. Due to the existence of RECLAIM, which caps $NO_x$ emissions in SoCAB, the local emissions in this study are somewhat unique. If other locations were chosen for the study's perspective, these emissions could differ depending on the local air quality regulations. The production and distribution emission sources for electricity are indicated in Table C-23.

Additional emissions from electricity distribution should also be accounted for in the analysis. Typical losses range from 3.5 to 13.5 percent, with higher losses on hot days. CEC estimated the distribution losses in a 1996 study for Los Angeles Dept of Water and Power and Southern California Edison to be around 9 percent and 7 percent, respectively.

**Table C-23: Electricity Production and Distribution Phases[a]**

| | Process | Emission Sources | Urban Emissions[b] |
|---|---|---|---|
| 1 | Extraction | Compressors, fugitive | — |
| 2 | Transport | Natural gas pipeline (compressors and fugitive) | 40% SC, 4%CA |
| 3 | Production | Fugitive emissions, combustion emissions | 40% SC, 4% CA |
| 4 | Site storage | — | 0 |
| 5 | Transport to bulk storage | Transmission line losses | 0 |
| 6 | Bulk storage | — | — |
| 7 | Transport to local station | — | — |
| 8 | Local station distribution | Distribution, lines, substation transformers, electrolyzer for hydrogen | 0 |

| Process | J/J | Input Fuels | Feedstock | Energy Calculations |
|---|---|---|---|---|
| 1 Extraction | 0.026 | | | |
| 3a Gas processing | 0.026 | | | |
| 5 Pipeline transport | 0.0132 | | | |
| 3b NG power plant | 2.35 | | | |
| 7 Transmission losses | 0.07 | | | |
| 8 Charger | | | | |
| **Fuel and Vehicle Cycle** | **2.72** | | **36.8%** | |




[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.5%. GREET assumptions, used in this study are 0% of the criteria pollutant emissions in urban areas. ROW urban emission estimates are baseline GREET assumptions and used in this study. Expressed as fuel cycle energy, extraction is 0.0256J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas.

2. Processing efficiency is assumed to be 97.8%. Gas processing and transport contribute 0.022 J/J gas processing plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for natural gas. Natural gas processing losses are assumed to be 0.15% which is the baseline GREET value.

3. Power generation efficiency for future marginal power assumed to be 8,500 Btu (HHV)/kWh based on heat rate profiles in Unnasch 2001.

7. Transmission losses for EVs assumed to be 7% with a high fraction of night-time charging.

8. Power consumption for EVs includes charger losses.

#### C.4.4.2 Applications for EVs and electrolysis

In the case of EVs, batteries on board the vehicles are charged from electricity on the grid. For fuel cell vehicles, the electricity is used to hydrolyze water, generating hydrogen. Electricity is then used to pump and compress the hydrogen in on-board storage tanks. The hydrogen is then converted to electricity in a fuel cell for operation of the vehicle motor. The fuel cycle emissions for the EV depend on the energy per mile required by the vehicle to operate and the emissions generated per unit of electrical energy generated and transmitted. There are losses during the vehicle charging but since EV energy consumption is reported in terms of kWh of electricity at the outlet, the energy consumption includes charging losses. For the fuel cell vehicle, the fuel cycle emissions depend on the mass of hydrogen per mile required, the energy required for electrolysis and compression, and the emissions generated per unit of electrical energy.

Table C-24 shows the steps and energy inputs associated with hydrogen production from electrolysis. The fuel cycle steps for power production are the same as electricity for EVs. For EVs charged at night, lower transmission losses were assumed. The same transmission losses were assumed for electrolysis.

Some developers argue that power produced at night would be more economic for hydrogen electrolysis. Renewable power is also considered as an option for EVs and electrolysis. The logistics of providing renewable power that is dedicated to vehicle use was not analyzed in this study. However, GHG emissions would be zero.

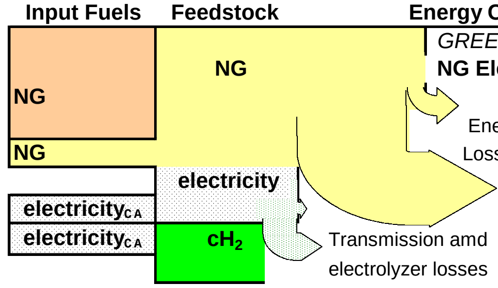
The marginal electricity for electric vehicles has been studied carefully. In addition to limited hydroelectric and nuclear capacity at the margin, one reason for the difference is that EV charging is expected to occur largely at night. Utilities will incentivize this nighttime charging in order to shift loads to off-peak hours. As a result, a variety of generation resources could be available to meet marginal EV demand. Hydrogen can also be produced off-peak and stored.

The assumptions for the fuel cycle emissions take into account several analyses and models. Different EV charging scenarios have been considered and are based on percentage of off-peak and on-peak charging. The analysis tools are described in the 2001 ARB Fuel Cycle Report (Unnasch 2001).

**Table C-24: Compressed Hydrogen from Electrolysis, On-site Production[a]**

| Process | | Emission Sources | Urban Emissions[b] |
|---|---|---|---|
| 1 | Extraction | Compressors, fugitive | — |
| 2 | Transport | Natural gas pipeline (compressors and fugitive) | 40% SC, 4%CA |
| 3 | Production | Fugitive emissions, combustion emissions | 40% SC, 4% CA |
| 4 | Site storage | — | 0 |
| 5 | Transport to bulk storage | Transmission line losses | 0 |
| 6 | Bulk storage | — | — |
| 7 | Transport to local station | Distribution, lines, substation transformers | — |
| 8 | Local station distribution | Electrolyzer for hydrogen | 0 |

| Process | J/J | Input Fuels | Feedstock | Energy Calculations |
|---|---|---|---|---|
| 1 Extraction | *0.026* | | | *GREET 1.6 CA* |
| | | | NG | **NG Electric Power** |
| 3a Gas processing | *0.026* | NG | | |
| 5 Pipeline transport | *0.0013* | | | |
| 3b NG power plant | *2.35* | NG | | |
| | | | electricity | |
| 7 Transmission losses | *0.07* | electricity$_{CA}$ | | |
| 8a Electrolyzer, compressor | 1.50 | electricity$_{CA}$ | $cH_2$ | |
| 8b Dispenser | 0.00001 | | | |
| **Fuel and Vehicle Cycle** | **4.08** | | **24.5%** | |




[a] SC = emissions occurring in the SoCAB. CA = California excluding SC, US = USA excluding CA. ROW = outside US. Fraction of urban emissions or transportation distance is indicated.

1. Natural gas extraction efficiency is 97.5%. GREET assumptions, used in this study are 0% of the criteria pollutant emissions in urban areas. ROW urban emission estimates are baseline GREET assumptions and used in this study. Expressed as fuel cycle energy, extraction is 0.0256J/J natural gas. This is not the total fuel cycle energy, but only the energy per unit of natural gas.
2. Processing efficiency is assumed to be 97.8%. Gas processing and transport contribute 0.022 J/J gas processing plant feedstock gas and 0% of emissions are assumed to occur in urban areas based on the baseline GREET assumptions. Energy inputs and fuel cycle energy for extraction and transport are shown in italics because these are included as an intermediate step in the fuel cycle results for natural gas. Natural gas processing losses are assumed to be 0.15% which is the baseline GREET value.
3. Power generation efficiency for future marginal power assumed to be 8,500 Btu (HHV)/kWh based on heat rate profiles in Unnasch 2001.
4. Bulk storage emissions are NMOG vapor losses. Fixed roof tanks with limited emission controls were assumed for site storage. The total fuel cycle losses are combined in on value in step 8. 20% of plant emissions are assumed to occur in urban areas which is the GREET baseline value. The product terminal may be located in a port, which is not adjacent to the production facility.
7. Transmission losses for EVs assumed to be 7%.

8a. Electrolyzer power requirement estimated to be 50 kWh/kg. Compressor energy inputs are 2.5 kWh/kg.

8b.Dispenser disconnect losses based on trapped volume of hydrogen. Product losses from steps 4, 6, and 8 are combined to determine total RNG required in Step 3.

## C.5 Efficiency and Transportation Assumptions

Fuel cycle $CO_2$ and other GHG emissions as well as local criteria pollutant emissions depend on energy inputs within the fuel cycle. For this study, calculations of energy efficiency for fuel cycle steps combined with transportation distances were used as inputs the GREET model to determine fuel cycle GHG emissions. Local criteria pollutant emissions were calculated consistent with energy input assumptions. The assumptions relating to the various steps in the fuel cycle are discussed below.

### C.5.1 Transportation Energy

Many fuel cycle steps and related assumptions are common among different fuel options. For example, natural gas extraction, marine vessel transport, and local truck transport are all steps used in the production of gasoline, LNG, methanol, and other fuels. The previous section described the steps associated with the production of each fuel. This section compares similar fuel cycle steps for all of the fuels in order to facilitate an overview of the assumptions. While these steps do not necessarily correspond to the same "phase" of the fuel production process, the comparison of similar metrics provides on overview of the consistency of key assumptions.

Stuff like transportation distance is different depending on the fuel production scenario. That is why it is cool to show them in one place and compare the transportation distances. Transportation distances for locations where natural resources or production facilities exist are shown in Table C-25.

**Table C-25: Distance to example locations for feedstocks and fuel production**

| | Total | Materials |
|---|---|---|
| Ocean Distances | | |
| Singapore | 7646 naut | FTD, Petroleum, LNG, Methanol |
| Venezuela | 3150 naut | Petroleum |
| Valdez, AK | 1967 naut | Methanol, Petroleum |
| Santiago, Chile | 4830 naut | Methanol, FTD, LNG |
| St. Louis, MO | 4830 naut | Ethanol (corn) |
| Rail/Truck/Pipeline Distances | | |
| Grand Island, NE | 1192 mi | Ethanol (corn), Biodiesel |
| Albuquerque, NM | 665 mi | Natural Gas, LPG, LNG |
| Calgary, Alberta | 1209 mi | Natural Gas, LPG |
| xxx, AK | 2600 mi | Natural Gas |
| Woody, CA | 137 mi | Ethanol (biomass) |

Similarly, the production of most fuels includes a conversion or refining step. While extensive analyses have gone into determining the efficiency of fuel refining, the efficiency of the fuel production step is typically treated as in input in fuel cycle studies.

The major assumptions that affect fuel cycle energy and emissions are presented here and compared among the different fuels. These assumptions include extraction efficiencies, transportation distances, and fuel conversion efficiencies. These parameters all affect energy inputs and GHG emissions. Some of the parameters also affect local emissions.

Detailed assumptions that affect local emissions are discussed in Section C.6.

Table C-26 shows the transportation distance assumptions for liquid fuels. These values are used to estimate energy inputs and emissions for each fuel. Local emissions are calculated from the assumed transportation distance in California while total energy inputs and GHG emissions are calculated the worldwide transportation distance.

**Table C-26: Bulk transportation assumptions for liquid fuels.**

| | California | | Worldwide[a] | | Outside California | |
|---|---|---|---|---|---|---|
| **Fuel Option** | **Ship** | **Rail** | **Ship** | **Rail** | **Ship[b]** | **Rail** |
| RFG/CARBOB, petroleum | 26 | 0 | 5400 | 0 | 26 | 0 |
| ULSD, petroleum | 26 | 0 | 5400 | 0 | 26 | 0 |
| LPG, petroleum | 26 | 0 | 5400 | 0 | 26 | 0 |
| LPG, NG | 0 | 70 | 0 | 2000 | 0 | 70 |
| M100, NG | 26 | 0 | 5400 | 0 | 26 | 0 |
| FTD, NG | 26 | 0 | 5400 | 0 | 26 | 0 |
| LNG, NG | 13 | 35 | 5400 | 200 | 13 | 35 |
| E100, Corn | 13 | 35 | 2150 | 1000 | 13 | 35 |
| E100, Biomass | 0 | 20 | 0 | 0 | 0 | 20 |
| Biodiesel | 0 | 70 | 0 | 3000 | 0 | 70 |

[a] Distances for fuel distribution (mi)
[b] Nautical miles, kn (2000 yards)

For most of the fuels considered in the scenario for marginal fuel production includes feedstock extraction and some or all of the refining outside of California. Criteria pollutant emissions outside of California are also estimated based on the transportation distance assumptions indicated and the estimates of emission rates in Section C.6.

### C.5.2 Bulk Liquid Fuel Transport

Table C-27 shows the estimated worldwide transportation distance for bulk liquid fuel, feedstock, or blending component transportation. The distances for estimating local emissions are shown for California and outside California. A transportation distance of 26 miles was assumed for blending component or fuel transportation distance outside California. This distance is consistent with the 26-mile value used in determining the marine vessel inventory of the SoCAB but was also applied to railcar transportation as many fuel production facilities outside of California are not likely to be in urban areas.

**Table C-27: Energy Inputs for Bulk Fuel Transportation**

| Fuel | Density[a] gal/ton | Capacity L product/L | gal Prod per DWT | LHV MJ/L | Energy, LHV (GJ/DWT) Product | Ship | Rail | ME (J/J) |
|---|---|---|---|---|---|---|---|---|
| CARBOB | 328 | 0.95 | 240 | 31.6 | 28.7 | 0.294 | — | 0.011 |
| ULSD | 286 | 0.95 | 271.4 | 35.4 | 36.4 | 0.294 | — | 0.011 |
| LPG. Petroleum | 476 | 0.90 | 428.6 | 23.2 | 37.6 | 0.294 | — | 0.010 |
| LPG, NG | 476 | 0.90 | 428.6 | 23.2 | 37.6 | — | 1.06 | 0.013 |
| M100 | 303 | 0.95 | 287.9 | 15.8 | 17.2 | 0.294 | — | 0.024 |
| FTD | 307 | 0.95 | 291.9 | 34.3 | 37.9 | 0.587 | — | 0.011 |
| LNG | 571 | 0.70 | 400.0 | 19.8 | 30.0 | 0.294 | 0.106 | 0.04 |
| LH2 | 3770 | 0.15 | 566.0 | 8.2 | 17.6 | 0.000 | — | — |
| E100, corn | 303 | 0.95 | 287.9 | 21.2 | 23.1 | 0.167 | 0.53 | 0.018 |
| E100, biomass | 303 | 0.95 | 287.9 | 21.2 | 23.1 | — | — | — |
| Biodiesel | 271 | 0.95 | 257.5 | 36.0 | 35.1 | — | 1.59 | 0.02 |

[a]Short tons (2000 lb) are typically used to describe cargo capacity.

The implications of bulk fuel transportation assumptions in Table C-28 on the fuel cycle emissions analysis include the following:

- Local emissions of criteria pollutants in California are based on the transportation distance in the SoCAB plus rest of California transportation
- The non SoCAB emissions in CA are weighted by a factor of 0.05 to reflect a lower rural population density.
- Total worldwide transportation distances are used to determine total WTW energy inputs and GHG emissions
- Out of CA transportation emissions are calculated based on an assumed 26 mile (nautical) transportation distance.

The contribution of bulk fuel transportation to total fuel cycle energy consumption is shown in Table C-27. The energy inputs are determined for each fuel based on transportation distances, cargo carrying capacity, and energy consumption for tanker ships or rail cars. The cargo capacity and related tanker ship fuel consumption depends on the weight of the fuel; so the volumetric capacity varies with fuel density.

The capacity of the tanker in gallons of product per DWT is also shown. Tankers carry about 95 percent of their weight capacity as cargo with the balance being consumables and ballast. Thus 95 percent of a short ton results in 288 gal of methanol per DWT (2000 lb/ton/6.6 lb/gal × 0.95 capacity. However, the cargo capacity of liquefied fuels is lower per ton than conventional liquid fuels. The reduced cargo capacity is primarily due to the lower density of liquefied gases as the storage tank would become unmanageably large if one ton of fuel were hauled for every ton of carrying capacity.

Bulk fuel transportation distance were used an input to the GREET 1.6 model. The composite energy input for bulk fuel transportation is shown in Table C-27. This energy input is expressed on a J/J basis (transportation fuel/product fuel) on an LHV basis. Energy inputs for bulk fuel transportation range from about 1 to 3 percent of product fuel. This ratio depends on the assumed transportation distance, mix between ship and rail, cargo capacity, as well as the product fuel's energy density.

### C.5.3 Tank Truck Transportation

Table C-28 shows the local transportation distance assumptions for liquid fuels. A 50-mile on-way trip was assumed as a transportation distance for all fuels except liquid hydrogen and LNG. The 50-mile distance reflects a transportation distance that would be typical for the SoCAB and other urban areas in California.

**Table C-28: Local Transportation Assumptions for Liquid Fuels**

| Liquid Fuels | Truck Use (miles one-way) | Truck Capacity (gal) | Fuel Density (lb/gal) | Fuel Weight (lb) | LHV (MJ/L) | Product Energy GJ | Module Energy (J/J) |
|---|---|---|---|---|---|---|---|
| ULSD | 50 | 7200 | 7.0 | 50400 | 35.4 | 965 | 0.0014 |
| LPG | 50 | 10000 | 4.2 | 42000 | 23.2 | 878 | 0.0015 |
| M100 | 50 | 7800 | 6.6 | 51480 | 15.8 | 467 | 0.0029 |
| FTD | 50 | 7900 | 6.51 | 51429 | 34.3 | 1026 | 0.0013 |
| LNG | 50 | 10000 | 3.5 | 35000 | 19.8 | 749 | 0.0016 |
| LH2 | 50 | 15000 | 0.53 | 8160 | 8.2 | 478 | 0.0023 |
| RFG3 | 50 | 8000 | 6.03 | 48240 | 31.2 | 945 | 0.0014 |
| E10 | 50 | 8000 | 6.15 | 49068 | 21.2 | 642 | 0.0015 |
| E65 | 50 | 7870 | 6.4 | 50542 | 24.91 | 742 | 0.0018 |
| E85 | 50 | 7830 | 6.5 | 51078 | 22.79 | 675 | 0.0020 |
| B20 | 50 | 7160 | 7.1 | 50649 | 35.08 | 951 | 0.0014 |
| FTD33 | 50 | 7431 | 6.8 | 50740 | 35.037 | 986 | 0.0014 |

For alternative fuels including methanol, ethanol, FTD, and biodiesel, sufficient bulk terminals capacity was assumed to allow for a 50-mile truck transportation distance. Volumes of alternative fuel usage on the order of 3 percent of gasoline demand or greater are assumed in the CEC petroleum dependency analysis (CEC 2002). Under such circumstances some pipeline construction could be expected to reduce truck transportation requirements. (Industry comments in Unnasch 1996). The truck carrying capacity is based on experience with procuring fuels.

For the cryogen fuels, LNG, and LH2, a greater transportation distance was assumed because the number of bulk storage facilities would be limited. LNG would be distributed directly from peak shaving facilities or LNG import terminals in California. Intermediate production terminals would be unlikely, as the cryogenic fuels cannot readily be transported by pipeline. The volumetric cargo capacity for LNG, LPG, and LH2 is greater

The transportation energy input required to haul fuels by truck is indicated for each fuel. The energy corresponds to the transportation distance and the delivery truck fuel consumption (estimated to be 5 mpg (Wool).

The gallon carrying capacity depends on the liquid fuel density since the truck must meet axle weight requirements. The values shown in the table are typical for current fuel deliveries. For reformulated diesel, it is unlikely that the load will be varied to take into account small differences in fuel density. Some tank trucks are equipped to deliver greater loads. However, the greater fuel load would result in reduced truck fuel economy and greater emissions per mile. The values in Table C-28 are consistent among the alternative fuel options.

### C.5.4 Pipeline Transport

Table C-29 shows the distance assumptions for natural gas distribution by pipeline. Total pipeline transportation distance is an input distances for estimating local emissions are shown for in the SoCAB, rest of California and outside California. Local emission estimates discussed in Section C.6 are assumed to be proportional to transportation distance, engine energy consumption and emission rates that are applicable for the region. A transportation distance of 100 miles was assumed for determining local criteria pollutant emissions from pipeline transportation outside California.

Table C-30 shows the energy inputs for all the fuel cycle steps. Many of the fuel cycle values are identical. For example, natural gas for power, CNG, and hydrogen for on-site production are all the same inputs and efficiencies.

**Table C-29: Pipeline Transportation Distance Natural Gas**

| Product | SoCAB | CA | US | ROW | Total |
|---|---|---|---|---|---|
| CNG | 70 | 230 | 970 | 1000 | 2270 |
| Hydrogen, steam reforming | 70 | 230 | 970 | 1000 | 2270 |
| Electric Power | 70 | 230 | 970 | 1000 | 2270 |
| Hydrogen, electrolysis | 70 | 230 | 970 | 1000 | 2270 |
| LNG, RNG | 0 | 0 | 0 | 400 | 400 |
| Methanol, RNG | 0 | 0 | 0 | 200 | 200 |
| FTD, RNG | 0 | 0 | 0 | 200 | 200 |

**Table C-30: Efficiency of Fuel Cycle Steps**

| Liquid Fuels | Extraction | Processing | NG Transport | Refining | Bulk Transport | Truck Transport |
|---|---|---|---|---|---|---|
| RFG3, Petroleum | 96.9% | -- | 99.9% | 87.9% | 99% | 99.9% |
| ULSD, Petroleum | 96.9% | -- | 99.9% | 83.9% | 99% | 99.9% |
| LPG, Petroleum | 96.9% | 96.5% | 99.9% | 97% | 99% | 99.9% |
| FTD, RNG | 97.5% | 99.0% | 99.9% | 63.0% | 99% | 99.9% |
| Methanol, RNG | 97.5% | 99.0% | 99.9% | 68.5% | 98% | 99.8% |
| LNG, RNG | 97.5% | 97.5% | 99.9% | 90.3% | 98% | 99.8% |
| **Gaseous Fuels** | **Extraction** | **Processing** | **NG Transport** | **Refining** | **Transmission** | **Fuel Station** |
| CNG, NG | 97.4% | 97.8% | 98.7% | -- | -- | 97.3% |
| cH2, NG On-site SR | 97.4% | 97.8% | 98.7% | -- | -- | 74.7% |
| cH2, NG, central SR LH2 | 97.4% | 97.8% | 98.7% | 79%, 67.5% | 99.5% | 99.9% |
| Electricity, NG | 97.4% | 97.8% | 98.7% | 37.9% | 93% | 100% |
| cH2, electrolyzer, NG | 97.4% | 97.8% | 98.7% | 37.9% | 93% | 72.1% |

## C.6 Local Emissions from Fuel Production and Distribution Processes

This section describes emissions from feedstock extraction, fuel production, and distribution. The emissions sources are covered roughly in order from extraction through distribution with some overlap. Section C.4.1 reviews emission rates from equipment used in transporting feedstocks and fuel and in processing operations. Energy usage rates for transportation equipment are also discussed in Section C.4.1.

Fuel production emissions and energy inputs are covered in Sections C.4.2 through C.4.3. The allocation of energy use to product fuels is discussed. While fuel production processes have a minor or no effect on marginal NMOG or $NO_x$ emissions in the SoCAB, they are still analyzed as they affect global $CO_2$ emissions. Fuel processing is defined as the conversion of feedstock material into end use fuel, or fuel production. Feedstock input requirements also relate to feedstock extraction requirements in Section C.4.1. Several fuels are processed from a combination of feedstocks and process fuels. Oil refineries and gas treatment plants produce multiple fuel products. Many production facilities import or export electricity, and excess heat energy can be exported to other facilities,

Section C.4.9 discusses emissions from fuel storage and distribution. These represent the most significant sources of marginal NMOG emissions. Local fuel cycle emissions are presented in terms of emissions per unit of fuel distributed (i.e. actual gallons of fuel). This approach allows for a more direct comparison with the steps in the fuel cycle.

For example, consider a diesel delivery truck with 7,800 gal of fuel traveling a 50-mi round trip route. A diesel truck fuel consumption of 5 mi/gal is expressed in energy terms as 0.0011 J/J product based on lower heating values. Expressing all of the fuel processing steps in energy terms allows for a convenient comparison amongst different fuel-cycle emission studies. In the case of fuel delivery trucks, a constant mileage is assumed for all fuel types and emissions are calculated from the g/mi emissions and truck fuel capacity to yield g/gal of delivered fuel. The energy associated with each step in the fuel cycle is also determined to calculate GHG emissions.

#### Local Emission Constraints

Emissions depend on the location of equipment and the prevailing (and prior) emission standards. Vehicles and combustion equipment in the SoCAB are and will continue to be subject emission controls, as are equipment in other populated areas of the state. Emissions from storage, distribution, and refueling losses are also consistent throughout the state. This allows SoCAB to be a proxy for local emissions in other regions that have emission sources.

Table C-31 shows $NO_x$ limits on combustion sources in the SoCAB. Boilers and gas turbines have been subject to Best Available Control Technology (BACT) requirements since the 1980s. All equipment installed since that time would meet $NO_x$ levels consistent with Rule 474. More recent installations will need to meet stricter $NO_x$ limits under Rule 1134. $NO_x$ levels of 9 ppm can only be met with Selective Catalytic Reduction (SCR), and actual emissions with SCR are one-half of this level.

Emission limits under Rules 474, 1110, 1134, and 1146 are expressed in ppm. These were converted to lb $NO_2$/MMBtu using a fuel factor of 8740 dry scf/MMBtu for natural gas and 9220 dry scf/MMBtu for diesel fuel. These emissions are expressed in lb/MWh or g/hp-hr for the energy consumption assumptions shown in the table.

### C.6.1 Fuel Extraction, Transportation, and Processing Equipment

Several types of equipment are used repeatedly throughout the estimation of fuel-cycle emissions. For example, diesel powered tanker trucks are used to move gasoline, diesel, LPG, ethanol, LNG, and methanol fuels from storage locations. Natural gas engines and gas turbines compress natural gas and are used in a variety of fuel industry applications. These engines are used to transmit natural gas feedstock to oil refineries, FT diesel, methanol, and electric power plants. This section summarizes the emissions and estimated usage rates for various types of equipment.

#### C.6.1.1 Truck Emissions

Tanker trucks are used to haul fuel for local delivery. Table C-32 shows the emission rates from heavy-duty trucks. The EMFAC model estimates truck emissions for the average truckload and weight. These estimates are based on engine dynamometer results in g/bhp-hr which are converted to g/mi. The conversion factor implicitly takes into account driving patterns and vehicle loads that probably do not reflect those of tanker trucks.

**Table C-31: Summary of SCAQMD $NO_x$ Rules**

| **Rule 474 — Fuel Burning Equipment — Oxides of Nitrogen** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Emission Source** | **Non-Mobil Fuel Burning Equipment** | | | | | | **Steam Generating Equipment** | |
| Heat rate (MBtu/hr) [a] | 555 to 1,785 | | 1,786 to 2,142 | | >2,143 | | >555 | |
| Fuel | Gas | Oil | Gas | Oil | Gas | Oil | Gas | Oil |
| $NO_x$ emissions[b] | | | | | | | | |
| (ppmvd @ 3% $O_2$) | 300 | 400 | 225 | 325 | 125 | 225 | 125 | 225 |
| (lb/MMBtu) | 0.37 | 0.52 | 0.28 | 0.42 | 0.15 | 0.29 | 0.15 | 0.29 |

| **Rule 1109 — Emissions of Oxides of Nitrogen for Boilers and Process Heaters in Petroleum Refineries** | |
|---|---|
| **Emission Source** | **Boilers and Process Heaters in Petroleum Refineries** |
| $NO_x$ (lb/MMBtu) | 0.03 |

| **Rule 1110.2 — Emissions from Stationary Internal Combustion Engines (gaseous- & liquid-fueled)** | | |
|---|---|---|
| **Emission Source** | **Stationary Internal Combustion Engines** | |
| Energy consumption (Btu/bhp-hr) | 8000 | 8000 |
| Fuel | gas | oil |
| $NO_x$ emissions[b] | | |
| (ppmvd @ 15% $O_2$) | 36 | 36 |
| (lb/MMBtu) | 0.134 | 0.141 |
| (g/bhp-hr) | 0.48 | 0.51 |

| **Rule 1134 — Emissions of Oxides of Nitrogen from Stationary Gas Turbines** | | | | | |
|---|---|---|---|---|---|
| **Emission Source** | **Simple Cycle** | **Simple Cycle** | **Simple Cycle No SCR[c]** | **Simple Cycle** | **Combined Cycle Power Plant with BACT[d]** |
| Unit size (MW) | 0.3 to 2.9 | 2.9 to 10 | 2.9 to 10 | >10 | >60 |
| Energy consumption | | | | | |
| (Btu/bhp-hr) | 13,000 | 13,000 | 11,000 | 11,000 | 5,200 |
| (Btu/kWh) | 17,000 | 17,400 | 14,750 | 14,750 | 7,000 |
| $NO_x$ emissions[b] | | | | | |
| (ppmvd @ 15% $O_2$) | 25 | 9 | 14 | 9 | 3 |
| (lb/MMBtu) | 0.093 | 0.0337 | 0.052 | 0.0337 | 0.011 |
| (g/hp-hr) | 0.55 | 0.20 | 0.26 | 0.17 | 0.026 |
| (lb/MWh) | 1.62 | 0.58 | 0.77 | 0.49 | 0.078 |

| **Rule 1146 — Emissions of Oxides of Nitrogen for Industrial, Institutional, and Commercial Boilers and Process Heaters** | |
|---|---|
| **Emission Source** | **Industrial, Institutional, and Commercial Boilers and Process Heaters** |
| $NO_x$ (lb/MMBtu) | 0.037 |

[a]Energy consumption (HHV) values are shown for reference.
[b]Emission rules apply on a ppm dry volume basis. $NO_x$ emissions are calculated from fuel factor (F) and $O_2$ content. Since excess air must be present to achieve combustion, the F factor is adjusted based on the presence of $O_2$. For example, at 15% excess, the F factor is multiplied by the natural percentage of $O_2$ in air of 20.9/(20.9%-15%) = 3.5. For example $NO_x$ in ppmvd is: 300 ppm x $10^{-6}$ scf $NO_x$ /scf exhaust x 3.5 scf @ 3% $O_2$/1 scf @ 0% $O_2$ x F.
[c]SCR = selective catalytic reduction
[d]BACT-best available control technology. Emission levels depend upon site specific parameters. Some power plants have been built with 3 ppm $NO_x$.

**Table C-32: Heavy-Duty Truck Emissions**

| Truck Type | 2020[a] 75,000 GVW |
|---|---|
| Fuel Economy (mi/gal) | 5.0 |
| MJ/km | 27,560 |
| **Emissions (g/mil)** | |
| CO | 1.0 |
| $NO_X$ | 0.7 |
| PM | 0.035 |
| NMOG | 0.14 |
| $CO_2$ | 2,000 |

Source: [a] LACMTA data, adjusted for load (Wool) adjusted EMFAC 2000, ARB 2003 standards rolled into fleet by 2010

More stringent emission controls consistent with EMFAC levels were assumed for 2020. These emission rates assume that ARB's 2003 standards, which require a 90 percent reduction in $NO_x$ and PM, are completely rolled into the fleet by 2010.The text should be rolled between the tables.

### C.6.1.2 Locomotive/Rail Emissions

Several fuels could be imported into the SoCAB by railcar. LPG produced from natural gas is shipped to California by railcar. Table C-33 shows the distances for hauling fuels by rail. If methanol were produced from biomass in the Central Valley, railcar transport would be an option. Emissions are determined from emission rates in g/bhp-hr and cargo load factors in hp-hr/ton-mi shown in Section C.5.

**Table C-33: Emission Factors for Rail Transport**

| Pollutant | Advanced Rail (g/1000 ton-mi) | (g/bhp-hr) |
|---|---|---|
| $NO_x$ | 610.4 | 7.0[b] |
| CO | 113.4 | 1.3 |
| $CO_2$ | 59,900 | 687 |
| NMOG | 69.8 | 0.8 |
| PM | 8.7 | 001 |

[a]Cargo factor = 87.2 hp-hr/net ton-mi. This cargo factor agrees with baseline GREET values.

[b]$NO_x$ for older locomotives is 11 g/bhp-hr.

### C.6.1.3 Marine Vessel Emissions

Crude oil and finished fuels are shipped in tanker ships. Tankers are powered by steam turbines as well as low speed diesels. The most prominent propulsion system for ocean going tankers is a two-stroke diesel (Burghardt).

Table C-34 shows emissions from typical marine diesel propulsion engines. The $NO_x$ emissions are comparable to or slightly higher than those from uncontrolled truck engines. Fuel consumption in g/bhp-hr is quite low. One reason for the lower fuel consumption is the higher caloric value of the heavy fuel oil used in marine diesels combined with combustion advantages of low speed operation and higher compression ratios. Fuel consumption of marine diesels has dropped from 140 to 120 g/bhp-hr over the past two decades (compared to 215 g/bhp-hr for a diesel engine on the EPA transient cycle). $NO_x$ levels depend on engine load over the ship's operating profile. Emission factors that take into account a ship's operating profile are expressed in g/kg fuel in Tables C-35 and C-36.

**Table C-34: Emissions from Marine Diesel Engines**

| Emission Source | Two-Stroke Diesel, Bunker Fuel | Four-Stroke Diesel, Bunker Fuel |
|---|---|---|
| Energy consumption (Btu/bhp-hr) | 5890 | 6086 |
| Fuel consumption (g/bhp-hr) | 120 to 140 | 120 to 140 |
| Emissions (g/bhp-hr) | | |
| $NO_x$ | 13.4 | 10.4 |
| CO | 0.15 | 0.75 |
| $CO_2$ | 448 | 463 |
| $CH_4$ | — | — |
| NMOG | 0.6 | 0.2 |
| PM | 0.5 | 0.5 |

Source: TIAX.

**Table C-35: Emissions and Use Factors for Tanker Ship Operations**

| Emission Source | 150,000 DWT tanker 1990 Diesel Motor | Maneuvering | Tankers |
|---|---|---|---|
| **At sea use factors** | | | |
| Fuel consumption (kg/ton-mi) | 0.0018 | | |
| Load efficiency | 0.95 | | |
| Fuel | Bunker fuel | | |
| Energy content (Btu/kg) | 40,350 | | |
| **At sea emissions (g/kg fuel)** | **g/kg** | **lb/1,000 gal** | **lb/1,000 gal** |
| $NO_x$ | 70 | 639 | 639 |
| CO | 1 | 58 | 55 |
| $CO_2$ | 3,300 | — | — |
| $CH_4$ | — | 19 | 18 |
| NMOG | 4 | 57 | 57 |
| PM | 1.5 | 3 | 3 |

Sources: Bremnes, Pera

**Table C-36: Emissions and Use Factors for Tug Boats and Ships**

| Emission Source | Tug Boats and Ships |
|---|---|
| In port use factors | |
| Port transit time (h) | 2 |
| Hotelling, pumping (h) | 30 |
| Tugboat operation (h) | 8 |
| Fuel use (kg/visit) | 7,716 |
| (kg/DWT) | 0.051 |
| Fuel | Diesel |
| Energy content (Btu/kg) | 42,560 |
| In port and tugboat emission factors (g/kg fuel) | |
| $NO_x$ | 37 |
| CO | 13.9 |
| $CO_2$ | 3,200 |
| $CH_4$ | — |
| NMOG | 6.9 |
| PM | 1.5 |

Sources: EPA AP-42, Kimble.

Tanker capacity is measured in dead weight tons (DWT) which includes the total carrying capacity of the ship. The load efficiency indicates what fraction of the total cargo capacity is actually carried. Fuel consumption decreases with larger tanker size. Tanker carrying load is measured in ton-miles. For marine applications, distance is measured in nautical miles (2000 yards), and speed is measured in knots or nautical miles per hour. For this analysis, crude oil, FTD, and methanol are shipped in 150,000 DWT tankers. Fuel consumption for tankers also varies with tanker speed and ocean conditions. Data from several sources (Kimble) indicate that the fuel consumption for a modern tanker is about 1.8 kg/1000 ton-mi. This fuel consumption is based on a round trip, carrying ballast on the return trip. This value agrees with baseline GREET values.

Tanker ships also produce emissions while in port. Auxiliary engines operate to produce electric power and tugboats maneuver the tanker into port or to the oil unloading platform. In-port time for tanker ships is generally as short as possible in order to maximize use of the tanker. In-port operation time and fuel consumption were estimated from information included in an ARB workshop on marine emissions. Tugboat fuel consumption is estimated from hours of tugboat operation and tugboat fuel consumption curves. $NO_x$ emission factors are lower for port operations than those for at sea operations because the engines operate at lower load, use lighter diesel oil, and a different mix of engines.

Section C.5 shows the marine transportation distance assumptions. The percentages represent the weighted average of the shipping distance that corresponds to the locations indicated in the table. Tanker travel distance in the SoCAB is taken to be 26 nautical miles. Several studies have considered the appropriate distance to include for marine vessel inventories (Port of Los Angeles). The SCAQMD boundaries include a 32 nautical mile section towards Ventura County and an 18 nautical mi. section to the South. Other studies have drawn an 88 nautical mile radius from shore or a similar shape out past San Clemente Island. Tanker ships probably reduce their power and coast when entering port that would lead to lower emissions along the coast. A relatively shorter (26 mi) tanker travel distance was assumed for this study while tanker emissions are not adjusted for reduced load. Assuming a longer distance and lower emissions would yield a similar result.

### C.6.1.4 Engine Emissions

Table C-37 summarizes the emission and performance characteristics of natural gas turbines used for natural gas transmission, prime movers. Table C-29 shows estimates of current and future emissions for turbines operating in the SoCAB, California, and the United States. Turbines operating outside of North America are assumed to emit at 1990 United States levels.

**Table C-37: Natural Gas Turbine Emissions**

| Turbine Location | SoCAB | | CA, U.S. | |
|---|---|---|---|---|
| **Year** | **1996** | **2020** | **1996** | **2020** |
| **Energy consumption (Btu/bhp-hr)** | **11,000** | **10,500** | **11,000** | **10,500** |
| **Emissions (g/bhp-hr)** | | | | |
| $NO_x$[a] | 0.3 | 0.17 | 1.4 | 0.5 |
| CO | 0.83 | 1.0 | 0.83 | 1.0 |
| $CO_2$ | 600 | 574 | 600 | 574 |
| $CH_4$ | 0.2 | 0.2 | 0.2 | 0.2 |
| NMOG | 0.01 | 0.01 | 0.01 | 0.01 |

[a] SCAQMD Rule 1134 requirements are equivalent to 0.03 to 0.5 g/bhp-hr.

Sources: Huey, A. D. Little, EPA. 1999.

Emissions in Table C-37 are shown in g/bhp-hr. These are converted to g/100 scf of natural gas transmitted.

Energy consumption (Btu/bhp-hr) and emissions are based on a population profile of gas turbines used as natural gas prime movers (Huey 1993) and emissions data for individual makes and models of gas turbines. The range of energy rates for gas turbine prime movers can vary from 10,000 to 13,000 Btu/bhp-hr. Heating values for stationary equipment is shown on a higher heating value (HHV) basis that is standard practice in the U.S. Further calculations involve lower heating values (LHV).

$NO_x$ emissions for gas turbines located in the SoCAB are based on SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) and an estimate of the types of gas turbines in the region. Because the $NO_x$ limit set forth in Rule 1134 varies according to control technology and rated power output, the $NO_x$ emission factor is an average emission factor for several types of gas turbines with varying power output and control technologies. The future $NO_x$ emission factor for gas turbines in the SoCAB is based on the emissions from the best available control technologies for gas turbines.

HC and CO emissions are consistent with EPA emission factors. $CO_2$ emissions are proportional to energy consumption.

Emissions data also show that methane emissions make up over 90 percent of the Total Hydrocarbons (THC) emissions from a gas turbine.

Table C-38 summarizes the emission and performance characteristics of natural gas reciprocating engines used for natural gas transmission, prime movers. Engines outside of North America are assumed to emit at the 1990 U.S. level.

**Table C-38: Natural Gas Reciprocating Engine Emissions**

| **Engine Location** | **SoCAB** | | **ROW** | **CA, U.S.** | |
|---|---|---|---|---|---|
| **Year** | **1996** | **2020** | **2020** | **1996** | **2020** |
| **Energy Consumption (Btu/bhp-hr)** | **8,000** | **7,800** | | **8,000** | **7,800** |
| **Emissions (g/bhp-hr)** | | | | | |
| $NO_x$[a] | 2 | 0.48 | 6 | 5 | 2 |
| CO | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 |
| $CO_2$ | 438 | 427 | 438 | 438 | 427 |
| $CH_4$ | 4.42 | 5 | 5 | 5 | 5 |
| NMOG | 0.45 | 0.5 | 0.5 | 0.5 | 0.5 |

[a] SCAQMD rule 1110.2 requirements are equivalent to 0.34 to 0.61 g/bhp-hr.

Sources: Huey, EPA 1999, A. D. Little

Energy consumption is based on a population profile of reciprocating engines prime movers (Huey) and emissions data for individual makes and models of engines. This value can range from 6,000 to 10,000 Btu/bhp-hr.

Population profiles of reciprocating engine prime movers indicate that the majority of these engines are lean-burn, with relatively few being stoichiometric rich-burn engines. The emission factors assigned to reciprocating engine prime movers are associated with lean-burn engines. Uncontrolled lean burn engines do not operate sufficiently lean to provide significant $NO_x$ reductions. All new lean burn engines sold in North America are configured for low $NO_x$ emissions.

$NO_x$ emissions outside the SoCAB (CA and the U.S.) are estimated to be 5 g/bhp-hr, which is based on an engine prime mover population and emissions profile. $NO_x$ emissions for an uncontrolled lean-burn prime mover range from 10 to 12 g/bhp-hr, whereas the emissions for a controlled lean-burn prime mover are about 1 to 2 g/bhp-hr (Huey 1993). Future $NO_x$ emissions for engines located in the SoCAB are estimated to be 0.48 g/bhp-hr, based on SCAQMD Rule 1110.2 (Emissions from Stationary Internal Combustion Engines).

CO and HC emissions are based on EPA emission factors and $CO_2$ is calculated from energy consumption and fuel properties. Similar to gas turbines, the emissions data also show that methane emissions makes up over 90 percent of the VOC emissions from an engine.

### C.6.1.5 Biomass Collection Equipment

Fuels and feedstocks are transported and distributed by a variety of equipment including trucks, trains, and marine vessels. Emissions from fuel or material transport were determined from emission rates and equipment usage factors that take into account distance traveled and cargo load. The emissions and use factors for the relevant fuels are discussed for each transportation mode. Several types of biomass are potential feedstocks for fuel production. Such feedstocks include agricultural residues, forest residues, and purpose grown energy crops. This study focuses on agricultural and wood residues. Feedstock transportation requirements for combustion of agricultural material and forest residue were used to estimate fuel usage in this study. The energy inputs are described in the 2001 ARB fuel cycle study.

While the collection of biomass results in emissions from gasoline and diesel equipment, the overall emissions associated with feedstock collection are likely to be a net negative. Collecting agricultural residue or forest waste results in a reduction in emissions from agricultural burns, prescriptive fires, and possibly wildfires. A report from the Energy Commission assesses the value of these emission reductions (Perez 2001).

### C.6.2 Refinery Emissions

In this study, it has been established that local emissions from refineries are independent of marginal California gasoline and diesel demand. It is expected that any reductions in fuel demand would result in reduced imports rather than reductions in refinery production. Nevertheless, for general information purposes, a discussion of refinery emissions is presented here.

A variety of petroleum products are produced from crude oil. Refineries produce gasoline, diesel, kerosene/jet fuel, LPG, residual oil, asphalt and other products. A variety of co-feedstocks, including natural gas, electricity, hydrocarbons from other refineries, and MTBE and other oxygenates, complicates the analysis of fuel-cycle emissions. Different crude oil feedstocks, gasoline specifications, and product mixes also complicates the picture for refineries.

Determining the emissions from the production of petroleum products involved the following approach. The SCAQMD emissions inventory includes emissions from oil production, refining, and distribution. These emissions are broken down by type, e.g. fugitives from valves and flanges. Emissions from base year, 1996, is based on emission use fees from stationary sources. These values were the basis for determining emissions on a gram per total amount of petroleum production basis. However, these emissions need to be allocated to the various refinery products in order to reflect the energy requirements for producing different fuels.

The output from a refinery model was used to determine the energy inputs required to produce different gasoline, diesel, and other petroleum products (MathPro 1998). Refinery combustion emissions were allocated to gasoline, diesel, and LPG in proportion to the energy requirements for refinery units. An energy allocation model was also used to determine changes in refinery energy needed to produce diesel and LPG. This approach results in the average emissions from refineries.

Emissions from refinery units in the model were allocated to the petroleum products produced by each refinery unit. For example, all of the combustion emissions associated with the diesel hydrodesulfurization unit are attributed to diesel fuel. Table C-39 shows the allocation of crude oil energy input and imported energy to diesel, RFD, and LPG.

**Table C-39: Allocation of Product Output and Energy Consumption for Refineries**

| Product | Crude Oil (gal/gal) | Natural Gas (100 scf/gal) | Electric Power (kWh/gal) | Energy[a] (Btu/gal) |
|---|---|---|---|---|
| RFG[b] | 0.94 | 0.18 | 0.27 | 157,000 |
| Diesel | 1.04 | 0.09 | 0.13 | 163,000 |
| RFD | 1.04 | 0.12 | 0.25 | 178,500 |
| LPG | 0.71 | 0.05 | 0.05 | 111,400 |

[a] Energy inputs based on allocation of energy inputs for MathPro refinery model. 103,000 Btu/100 scf natural gas and 9,000 Btu/kWh power.
[b] Includes 5.7% ethanol.

Source: A. D. Little

The SCAQMD emissions inventory provides insight into emissions from oil production, refining, and distribution in the four county SoCAB. See Unnasch 2001

### C.6.3 Alternative Fuel Production

The criteria pollutant emissions associated with methanol, FTD, ethanol, CNG, and LNG all occur outside of the SoCAB. As discussed in A.3, they are all produced in other regions of California or are imported from other states or countries. The emissions from these fuels are discussed in detail in the 2001 ARB Fuel Cycle Report (ARB 2001b) and in the 2001 CEC Biomass-to-Ethanol report (Perez, 2001).

### C.6.4 Fuel Storage and Distribution

This section describes the bulk storage and delivery of liquid fuels. Table C-44 shows the emissions from bulk storage tanks based on the calculation technique in AP-42.

According to the staff of the SCAQMD refinery and bulk storage inspection and permitting teams, floating roof tanks are the most common storage tank type in the SoCAB and will constitute the vast majority of storage facilities on the margin. These tanks comply with “Rule 463: Organic Liquid Storage” which regulates the storage of gasoline in above-ground tanks among other compounds. Tanks in bulk storage farms and refineries are often used to store more than one type of product including diesel and other intermediary refinery product.

Vapor controls are required to be at least 95 percent efficient. Internal and external floating roof tanks must be equipped with liquid mounted primary and secondary seals consistent with the best available technology. Other tanks are outfitted with vapor recovery systems that feed the recovered vapor either into an incinerator or a liquifier. In the study, a 90 percent reduction in emissions (reduction factor of 0.1) is assumed for methanol tanks in the SoCAB. Such controls were not assumed for diesel because its low vapor pressure avoids vapor control requirements.

Actual NMOG emissions are either capped by Best Available Control Technology requirements in the SoCAB or are naturally lower due to low vapor pressure, as indicated in Table C-40.

**Table C-40: Fugitive Hydrocarbon Emissions from Internal Floating Roof Storage Tanks**

| Fuel | RFG | Diesel | FTD | E100 | M100 |
|---|---|---|---|---|---|
| RVP (psi) | 6.80 | 0.022 | 0.030 | 2.3 | 4.63 |
| TVP (psi) | 6.10 | 0.015 | 0.02 | 1.7 | 3.50 |
| Temperature (°F) | 90 | 90 | 90 | 90 | 90 |
| MW | 76 | 130 | 120 | 46 | 32 |
| Tank capacity (bbl) | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 |
| Tank diameter (ft) | 100 | 100 | 100 | 100 | 100 |
| Tank height (ft) | 36 | 36 | 36 | 36 | 36 |
| Throughput (bbl/yr) | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| Throughput (gal/day) | 69,041 | 69,041 | 69,041 | 69,041 | 69,041 |
| Turnover (day/tank) | 30.42 | 30.42 | 30.42 | 30.42 | 30.42 |
| Emissions (lb/yr) | 6855 | 88 | 94 | 965 | 1,663 |
| Emissions (g/gal) | 0.1235 | 0.0016 | 0.0017 | 0.0174 | 0.0300 |

Source: TIAX

Table C-41 shows the actual values used in the report. Evaporative controls on bulk storage tanks limit emissions.

**Table C-41: NMOG Emissions from Bulk Fuel Storage**

| Fuel | Vapor Without Control (g/gal) | BACT (g/gal) |
|---|---|---|
| Gasoline | 0.123 | 0.0246 |
| Diesel | 0.0016 | -- |
| FTD | 0.0017 | -- |
| E100 | 0.0174 | -- |
| M100 | 0.030 | 0.0246 |

Source: BAAQMD

### C.6.4.1 Local Fuel Distribution — Liquid Fuels

This section describes the storage and distribution of liquid fuels at local service stations. These emissions consist of the following categories:

- Tank truck unloading spills and working losses: tank trucks unload fuel to storage tanks at fueling stations using Phase I vapor recovery.
- Under ground tank breathing: during the course of fuel storage, the vapor or ullage space in the tank expands and contracts as atmospheric pressure and fuel temperature change. Fuel temperature usually remains almost constant in underground tanks.
- Vehicle fuel tank filling (working losses): fuel is dispensed to vehicles with vapor recovery hose systems, called Phase II vapor recovery.

The different stages of fuel distribution were observed to provide insight for this project. There are no significant differences in the unloading of gasoline or alcohol fuels. Unloading is accomplished with appropriate precautions for safety and minimizing emissions. Fuel and vapor transfer hoses are connected from the storage tank to the truck. The truck carries its own fuel transfer hoses and an assortment of fittings for connection to the underground tank. After verifying the remaining tank volume with a dipstick measurement, the truck operator initiates the gravity fed unloading operation. When the fuel transfer is completed, the hoses are returned back to the tank truck. There is still a considerable volume of fuel in the fuel transfer hose (about 4-inch inner diameter). The truck operator disconnects the hose from the truck tank and drains the remaining fuel in the bottom of the hose into the underground storage tank by lifting the hose into the air and moving the elevated section towards the connection at the underground tank. The hose is then disconnected and stored on the truck. During several such fueling operations, about 250ml of fuel was observed spilling out of the hose as it was placed back into its holding tube on the truck. It was estimated that the volume from spills is about 180g for an 8,000 gal fuel load or 0.023 g/gal (0.05 lb/1000 gal). While this quantity is based on casual observations, it provides some quantification of a small source that is not explicitly counted in the inventory. It is difficult to spill no fuel during hose transfers since the inner wall of the transfer hose is covered with fuel as indicated by hooks on some tanker trucks for drying clean up rags. An even smaller amount of fuel may remain on the hose surface and evaporate later.

Truck transfer is intended to be a no spill operation. Drivers are instructed to drain the hose into the tank before placing it back on the truck. Catch drains at the top of underground tanks would capture some spilled fuel if it dripped from the tank connection. However, some wet hose losses are inevitable. The thin layer of fuel in the hose will result in some drips and evaporation. It should be pointed out that the volumes used in this study are based on rough estimates and do not reflect a large sample. Furthermore, liquid spill volumes are difficult to measure. While further quantification of the frequency and quantities of Phase I spillage would be necessary to assure the accuracy of this value, it is significantly smaller than Phase II spillage.

#### C.6.4.2 Vehicle Fueling Spillage

While most vehicle operations are successful with little fuel spilled from the nozzle, occasionally a significant quantity of fuel is spilled. Fuels spills and form vehicle refueling were evaluated by ARB in the Enhanced Vapor Recovery Standards and Specifications (July, 2001). The proposed rulemaking set standards for spillage, drips, and nozzle retention. These standards are presented in Table C-42. For calculation purposes, spillage, liquid retention, and nozzle spitting are lumped together on a g/gal basis. All of these emissions are event related. The amount of fuel spilled per event is constant; so, larger fuel tanks or volumes of fuel dispensed result in lower emissions per gallon dispensed. Historically, emission factors for spillage have been 0.7 lb/1,000 gal. With Phase II systems, this value was adjusted downward to 0.24 lb/1,000 gal. For Phase II systems, spillage plus liquid retention results in 0.40 lb/1,000 gal of gasoline.

**Table C-42: Standards for Gasoline Spillage, Dripping and Nozzle Retention**

| Source | Standard | Units |
|---|---|---|
| Phase II dispensing spillage | 0.24 | lb/1000 gal |
| Dripless nozzle | <1 | drops/fueling event |
| Liquid retention | 100 | ml/1000 gal |
| Nozzle spitting | 1 | ml/nozzle |

Source: ARB …. CP 201, 1999xxx, Unnasch 2001

The liquid retention emissions are based on gasoline evaporating from the nozzle. With methanol, this level of evaporation would be lower, and it would be virtually eliminated with diesel. The ARB emission factor for diesel spillage is 0.61 lb/1000 gal. The maximum for diesel spillage is higher than that of gasoline for several reasons. Since vapor emissions from diesel are much lower than those from gasoline, a higher spillage rate is allowed in the rules. Since diesel fueling occurs without vapor recovery, higher fueling rates are possible. The potential for spillage is potentially higher with higher fueling rates. Also, spillage volumes per unit fuel could be lower for smaller vehicles with smaller fueling volumes. The trade offs between fuel economy and spillage are analyzed in the 2001 ARB fuel cycle study. Spillage rates of other liquid fuels were estimated. Gasoline spill limits were assumed for RFG and ethanol blends. Diesel spillage limits were assumed for RFD, FTD, biodiesel, and blends of these products. Methanol fuel cell vehicles have special fittings to prevent fuel spillage (Heffelfinger).

**Table C-43: Vehicle Fuel Spillage Parameters for 2020**

| Fuel | Liquid Retention/Spillage (g/gal) |
|---|---|
| Diesel | 0.277 |
| RFD, biodiesel | 0.277 |
| LPG | 0.090 |
| FTD | 0.277 |
| M100 Fuel Cell | 0 |
| RFG3 | 0.182 |
| Ethanol blends | 0.182 |

Source: ARB regulations for diesel and gasoline fueling

### C.6.4.3 Vapor Space NMOG Mass

Vapor emissions in this study are determined from modeled vapor concentrations. The fuel temperature used to determine vapor concentrations was selected to be consistent with ARB's inventory for fueling station emissions.

The vapor concentration in the tank vapor space is the basis for fuel transfer emission calculations in AP-42 and provides insight into the temperature conditions for vapor emissions. Vapor space concentrations are modeled from equilibrium vapor concentration. The extent of vapor saturation is reflected by the saturation factor. For vapor recovery systems a saturation factor of 1.0 or completely saturated vapor is assumed in AP-42. ARB bases the vapor space concentration on test data. The vapor space gas concentration represents the uncontrolled emissions from tank truck unloading (underground tank working losses), and vehicle tank working losses.

Vapor space concentrations from liquid fuels were estimated from the ideal gas law. Given a molar volume of 379.6 $ft^3$/lb mole at 60°F, the equilibrium vapor ($V_e$) in a tank head space can be calculated from the following equation:

$$V_e \text{ (lb/gal)} = \text{MW(lb/mol)} \times \text{lbmol}/379.6 \text{ ft}^3 \times 0.1337 \text{ ft}^3\text{/gal} \times \text{TVP}/14.7 \text{ psi} \times 520°\text{R}/\text{T}$$

Where:

T = gas and liquid temperature (°R)
TVP = true vapor pressure (psi) at the equilibrium temperature

The same temperature conditions were emission estimates that are consistent with California inventories. This effectively results in an equivalent equilibrium temperature that reflects the actual range of fuel temperatures and saturation conditions that correspond to test data. The underlying assumption with this approach is that the inventory data is based on a broad range of conditions and reflects the suitable conditions. Shown in Table 4-44 are the vapor densities, which vary with temperature.

Vapor concentration (uncontrolled NMOG vapor mass) for this study was determined from equilibrium vapor densities that correspond to 70°F for underground tank vapors, and 76°F for vehicle fuel tank vapors. Actual vehicle vapor temperatures can be higher. The effect of higher vapor temperatures is also shown in Table 4-45.

Table C-46 also shows tank truck distribution emissions for liquid fuels. These emissions take into account vapor recovery effectiveness and a defect rate between zero and four percent for Phase II emission controls. The higher defect rate reflects the potential interaction between ORVR equipment and vapor control equipment or simply a less effective vapor recovery system. Since no methanol powered fuel cell vehicles or any passenger cars that operate on M100 are built in commercial volumes, emission control requirements can still be developed. Such emission control requirements would address Phase II efficiency requirements, refueling connections that reduce the risk of misfueling, ORVR requirements, and other details of refueling.

**Table C-44: Evaporative Emissions from Out of State Fuel Storage and Transfer**

| Emission Category/Fuel | TVP (psi) | MW (g/mol) | Effective Temperature (°F) | Uncontrolled NMOG Vapor Mass (g/gal) | Uncontrolled NMOG Vapor Mass (lb/1000gal) | Control Efficiency (%) | Controlled Vapor (g/gal) a |
|---|---|---|---|---|---|---|---|
| Marine vessel loading, overseas, Tank Working Loss | | | | | | | |
| Diesel | **0.0092** | **130** | 76 | 0.0126 | 0.03 | 0 | 0.0126 |
| BD2 | **0.0092** | **130** | 76 | 0.0126 | 0.0 | 0 | 0.0126 |
| BD20 | **0.0092** | **130** | 76 | 0.0126 | 0.0 | 0 | 0.0126 |
| FTD | **0.0092** | **120** | 76 | 0.0116 | 0.0 | 0 | 0.0116 |
| FTD33 | **0.0092** | 127 | 76 | 0.0123 | 0.03 | 0 | 0.0123 |
| M100 | **2.35** | 32 | 76 | 0.792 | 1.7 | 90 | 0.0792 |
| E100 | **1.50** | 46.05 | 76 | 0.73 | 1.6 | 90 | **0.073** |
| CARBOB | **4.84** | **76** | 76 | 3.88 | 8.5 | 90 | **0.388** |
| Marine vessel unloading, overseas, Tank Working Loss | | | | | | | |
| Diesel | **0.0092** | **130** | 76 | 0.0126 | 0.03 | 0 | 0.0126 |
| BD2 | **0.0092** | **130** | 76 | 0.0126 | 0.0 | 0 | 0.0126 |
| BD20 | **0.0092** | **130** | 76 | 0.0126 | 0.0 | 0 | 0.0126 |
| FTD | **0.0092** | **120** | 76 | 0.0116 | 0.0 | 0 | 0.0116 |
| FTD33 | **0.0092** | 127 | 76 | 0.0123 | 0.03 | 0 | 0.0123 |
| M100 | **2.35** | 32 | 76 | 0.792 | 1.7 | 90 | 0.0792 |
| E85 | **4.84** | **61** | 76 | 3.11 | 6.9 | 90 | 0.311 |
| E65 | **4.84** | 63 | 76 | 3.21 | 7.1 | 90 | 0.321 |
| E10 | **4.84** | 68 | 76 | 3.45 | 7.6 | 90 | **0.345** |
| Gasoline 7 RVP | **4.84** | **68** | 76 | 3.47 | 7.6 | 90 | **0.347** |

**Table C-45: Evaporative Emissions from Liquid Fuel Station**

| Emission Category/Fuel | TVP (psi) | MW (g/mol) | Effective Temperature (°F) | Uncontrolled NMOG Vapor Mass (g/gal) | Uncontrolled NMOG Vapor Mass (lb/1000 gal) | Control Efficiency (%) | Controlled Vapor (g/gal)[a] |
|---|---|---|---|---|---|---|---|
| Truck loading, Tank Working Loss | | | Limit 0.15 lb/1000 gal | | | | |
| Diesel | 0.0092 | 130 | 76 | 0.0126 | 0.03 | 0 | 0.0126 |
| BD2 | 0.0092 | 130 | 76 | 0.0126 | 0.0 | 0 | 0.0126 |
| BD20 | 0.0092 | 130 | 76 | 0.0126 | 0.0 | 0 | 0.0126 |
| FTD | 0.0092 | 120 | 76 | 0.0116 | 0.0 | 0 | 0.0116 |
| FTD33 | 0.0092 | 127 | 76 | 0.0123 | 0.03 | 0 | 0.0123 |
| M100 | 2.35 | 32 | 76 | 0.792 | 1.7 | 98 | 0.0158 |
| E85 | 4.84 | 61 | 76 | 3.11 | 6.9 | 98 | 0.062 |
| E65 | 4.84 | 63 | 76 | 3.21 | 7.1 | 98 | 0.064 |
| E10 | 4.84 | 68 | 76 | 3.45 | 7.6 | 98 | 0.069 |
| Gasoline 7 RVP | 4.84 | 68 | 76 | 3.47 | 7.6 | 98 | 0.069 |
| Truck Unloading, Underground Tank Working Loss | | | Limit 0.15 lb/1000 gal | | | | |
| Diesel | 0.0090 | 130 | 70 | 0.0125 | 0.03 | 0 | 0.0125 |
| BD2 | 0.0090 | 130 | 70 | 0.0125 | 0.0 | 0 | 0.0125 |
| BD20 | 0.0090 | 130 | 70 | 0.0125 | 0.0 | 0 | 0.0125 |
| FTD | 0.0090 | 120 | 70 | 0.0115 | 0.0 | 0 | 0.0115 |
| FTD33 | 0.0090 | 127 | 70 | 0.0122 | 0.03 | 0 | 0.0122 |
| M100 | 1.95 | 32 | 70 | 0.667 | 1.5 | 98 | 0.0133 |
| E85 | 4.30 | 61 | 70 | 2.80 | 6.2 | 98 | 0.056 |
| E65 | 4.30 | 63 | 70 | 2.88 | 6.3 | 98 | 0.058 |
| E10 | 4.30 | 68 | 70 | 3.10 | 6.8 | 98 | 0.062 |
| Gasoline 7 RVP | 4.30 | 68 | 70 | 3.12 | 6.9 | 98 | 0.062 |
| Underground Tank Breathing Loss | | | All tanks under negative pressure | | | | |
| Diesel | 0.0090 | 130 | 70 | 0.0125 | 0.03 | 90 | 0.001 |
| BD2 | 0.0090 | 130 | 70 | 0.0125 | 0.0 | 90 | 0.001 |
| BD20 | 0.0090 | 130 | 70 | 0.0125 | 0.0 | 90 | 0.001 |
| FTD | 0.0090 | 120 | 70 | 0.0115 | 0.0 | 90 | 0.001 |
| FTD33 | 0.0090 | 127 | 70 | 0.0122 | 0.03 | 90 | 0.001 |
| M100 | 1.95 | 32 | 70 | 0.667 | 1.5 | 99 | 0.007 |
| E85 | 4.30 | 61 | 70 | 2.80 | 6.2 | 99 | 0.028 |
| E65 | 4.30 | 63 | 70 | 2.88 | 6.3 | 99 | 0.029 |
| E10 | 4.30 | 68 | 70 | 3.10 | 6.8 | 99 | 0.031 |
| Gasoline 7 RVP | 4.30 | 68 | 70 | 3.12 | 6.9 | 99 | 0.031 |

[a]AP-42 Sec 7, U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources,* January 1995.
Methanol TVP from AP-42 Table 7.1-3. Diesel, Gasoline TVP from AP-42 Table 7.1-2.
Molecular weight of E85 based on test data, Unnasch 1996.
Molecular weight is weighted average of E85 and E5.7.
Assumed molecular weight of 68 for gasoline with RVP of 7 based on AP-42. Data from gasoline vapor space indicates a higher MW (71), Unnasch 1996.
For values in bold, assumed emission limit in CP-201, Arb, 2001.
X BAAQMD 8-33-301, Bulk Gasoline Terminal Limitation for filling 0.08 lb/1000 gal. (BAAQMD)

**Table C-46: Evaporative Emissions from Vehicle Fueling.**

| Emission Category/Fuel | TVP (psi) | MW (g/mol) | Effective Temperature (°F) | Uncontrolled NMOG Vapor Mass (g/gal) | (lb/1000gal) | Control Efficiency (%) | Controlled Vapor (g/gal)[a] |
|---|---|---|---|---|---|---|---|
| Vehicle Working Loss | | | Limit 0.38 lb/1000 gal | | | | |
| Diesel | 0.0120 | 130 | 80 | 0.0163 | 0.04 | 0 | 0.0163 |
| BD2 | 0.0120 | 130 | 80 | 0.0163 | 0.0 | 0 | 0.0163 |
| BD20 | 0.0120 | 130 | 80 | 0.0163 | 0.0 | 0 | 0.0163 |
| FTD | 0.0120 | 120 | 80 | 0.0151 | 0.0 | 0 | 0.0151 |
| FTD33 | 0.0120 | 127 | 80 | 0.0159 | 0.04 | 0 | 0.0159 |
| M100 | 2.61 | 32 | 80 | 0.875 | 1.9 | 95 | 0.0437 |
| E85 | 5.20 | 61 | 80 | 3.32 | 7.3 | 95 | 0.166 |
| E65 | 5.20 | 63 | 80 | 3.42 | 7.5 | 95 | 0.171 |
| E10 | 5.20 | 68 | 80 | 3.68 | 8.1 | 95 | 0.184 |
| Gasoline 7 RVP | 5.20 | 68 | 80 | 3.70 | 8.2 | 95 | 0.185 |

[a]AP-42 Sec 7, U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources,* January 1995.
Methanol TVP from AP-42 Table 7.1-3. Diesel, Gasoline TVP from AP-42 Table 7.1-2.
Molecular weight of E85 based on test data, Unnasch 1996.
Molecular weight is weighted average of E85 and E5.7.
Assumed molecular weight of 68 for gasoline with RVP of 7 based on AP-42. Data from gasoline vapor space indicates a higher MW (71), Unnasch 1996.
For values in bold, assumed emission limit in CP-201, Arb, 2001.
X BAAQMD 8-33-301, Bulk Gasoline Terminal Limitation for filling 0.08 lb/1000 gal. (BAAQMD)

### C.6.4.4 LPG Distribution

LPG is stored and distributed in pressurized tanks. The fuel is stored in a liquid state at ambient temperature and the pressure in the tank is in equilibrium. At 70°F the storage pressure is 105 psig. When LPG is transferred from a storage tank to a tank truck, or to a vehicle fuel tank, a transfer pump provides about 50 psi of differential pressure. When fueling vehicle tanks, the fuel enters the tank and the LPG ullage condenses. This process can be accelerated with top loaded tanks where the liquid spray can absorb some of the heat from condensing the vapors.

The tank trucks are filled at refineries with a two hose system with one hose acting as a vapor return. Hoses are evacuated after fuel transfer operations at the refinery. Tank trucks can be filled to a safe fraction of its water capacity by weighing the truck during fueling (Lowi 1994), although this is not the current practice. However, current regulations require the use of an "outage" valve that indicates when the tank is full. Some LPG also enters the atmosphere from the fuel transfer fitting.

Table 4-37 shows the emissions associated with LPG storage and distribution. The LPG emissions correspond to the volume of liquid that escapes from the fuel transfer fitting divided by the amount of fuel transferred. Currently, LPG vehicles in California are equipped with an “outage” valve that indicates the 80 percent fill level by spilling LPG to the atmosphere. During vehicle fueling, the outage valve is opened and vapors pass through a 0.060-inch orifice and through the valve. When LPG reaches the 80 percent level in the vehicle tank, liquid enters the fill level line and exits into the atmosphere. A puff of white liquid is visible to the fueler that provides an additional signal that the tank is full. California's vehicle code requires use of the outage valve. As indicated in Table C-47, emissions from vehicle fueling are several grams per gallon.

**Table C-47: Fuel from LPG Fuel Delivery**

| Emission Source | Tank Volume (gal) | Liquid Spill Volume (ml/fill) | Liquid Spill Volume (ml/gal) | Spill Rate (g/gal) |
|---|---|---|---|---|
| Transfer tank outage[a] | 10,000 | — | — | 1 |
| Bulk tank outage | 30,000 | — | — | 0.2-0.5 |
| Truck fill outage[a] | — | — | — | 2 |
| Truck fill hose | 3,000 | 1,391 | 0.139 | 0.070 |
| Local tank hose | 1,000 | 17.4 | 0.0017 | 0.0008 |
| Local tank outage[a] | — | — | — | 5 |
| Vehicle tank outage | — | — | — | 0 |

[a]Better vapor management could eliminate this emissions source by the year 2010.

Many LPG tanks are already equipped with automatic stop-fill devices that could eliminate fuel tank vapor venting; however, Titles 8 and 13 of the California Administrative Code require the use of the outage valve. Other countries, including the Netherlands where many LPG vehicles operate, do not use the outage valve for fueling. One might expect that many LPG vehicles in California are fueled without using the outage valve if they are equipped with automatic stop fill devices.

A committee of NFPA, CHP, NPGA, and WLPGA representatives are working to set standards that will allow LPG vehicles to be fueled without leaking LPG to the atmosphere. Equipment that will minimize the fuel released from transfer fittings is also being approved (Wheeler 1994). EPA regulations on evaporative emissions from vehicles will also eliminate vehicle outage valve emissions.

Emission estimates for LPG fueling are based on the following conditions:

- 1391 cc loss from fuel couplings on 10,000 gal delivery trucks. Fluid loss is equivalent to 18 in of 1.25-in (inner diameter) hose (Lowi 1992)

- Current vehicle hose coupling liquid losses are 7.57 cc (Lowi 1992) for a 12 gallon fuel transfer. Dry-break couplings would have less than 5 percent of the trapped volume of current LPG nozzles of the same capacity.

- Current fuel tank vapor displacement is based on sonic flow through a 1.5 mm orifice, 70°F tank temperature with a fuel pressure of 105 psig. Assuming an orifice discharge coefficient of 0.5 results in 2 g/s of vapor flow. With an 8 gal/min flow rate, vapor displacement is 15 g/gal.

- Vapor displacement from current tank truck filling assumes a 100 gal/min fill rate with an outage loss of 2 g/s

### C.6.4.5 LNG Distribution

The losses associated with LNG fuel transfers are indicated in Table C-48. Fuel losses occur from hose disconnect events and from tank venting. These losses were assumed to be controlled by 90 percent by 2020.

**Table C-48: Fuel from LNG Fuel Delivery**

| Emission Source[a] | LNG loss (g/gal) |
|---|---|
| Boil Off Losses | 10 |
| Truck fill hose | 0.070 |
| Truck venting | 2.2 |
| Local tank hose | 1 |
| Vehicle hot tank venting | 0.5 |

[a]Better vapor management could eliminate this emissions source by the year 2020.

### C.6.4.6 CNG and Hydrogen Compression

Energy inputs for CNG and hydrogen compression are based on process modeling results assuming optimized compressor systems. Both CNG and hydrogen fueling will continue to be accomplished with electric compressors. Some natural gas engine compressor systems have been tried, however the issues associated with emissions permitting favor electric compressors. The method for gas storage and compression, type of gas, as well as final storage pressure affects the energy inputs for compression.

Slow fill (or time fill) systems compress the gas and directly fill the vehicle over an extended period of time (usually overnight). The compressor output is only slightly higher than the vehicle storage pressure.

Fast fill fueling requires slightly more energy as the gas stored at higher pressure prior to vehicle fueling. For cascase fast fill, natural gas is compressed and stored in several sets of storage cylinders (typically three). The cascade storage pressure is about 3600 psi for a 3000 psi vehicle storage system.

Also, fast fill fueling results in rapid compression and corresponding temperature rise of the gas in the vehicle. If the vehicle is fueled to 3000 psi, its final fill pressure will drop after the temperature in the vehicle tank equilibrates with ambient air. Sophisticated fueling systems that compensate for the ambient temperature and gas with the vehicle have been designed. Such systems would allow the vehicle to be filled to an effective pressure of 3000 psi. Therefore, after compression to 3600 psi and the fuel heating effect are taken into account, fast fill fueling requires about 22 percent more energy than those of slow fill fueling.

Actual data on CNG compressor systems is not widely available[27]. Compression energy ranging from 1.3 to 1.7 kWh/100 scf has been measured in real world fast-fill systems (Wang 1999, Unnasch 1993). Calculations of energy requirements, mechanical losses, motor efficiencies with more optimized efficiencies indicate electricity consumption below 0.8 kWh/100 scf (Lasher 2001). An improvement in compressor system efficiency resulting in a power consumption of 0.9 kWh/100scf was assumed for future systems.

### C.6.5 Analysis of Uncertainties

This section identifies the key uncertainties in fuel cycle emissions for each of the fuel options considered in this study, with emphasis given to the NMOG value. Several fuels are close the NMOG limit for the low fuel cycle emission portion of the PZEV allowance.

Figure C-12 shows the key parameters that affect NMOG emissions for gasoline fueled vehicles. The example shown here is for a mid-sized hybrid vehicles operating on RFG3. Spillage emissions are a significant source of marginal NMOG but estimates for these emissions has declined as ARB has. The range in spillage depends upon fuel tank size and the refueling spillage rate. This emission factor for spillage is based on the average vehicle; however, the spillage per gallon increases as fuel tank size decreases. Vehicles with improved fuel economy would have smaller fuel tanks and greater spillage per gallon. Based on limited data, fuel tank size is proportional to fuel economy; however, very efficient vehicles may tend to have somewhat greater range. Other parameters have a smaller effect on fuel cycle emissions.

Figure C-13 illustrates how total NMOG and spillage emissions are estimated to vary with fuel economy. Most of the fuel cycle emissions are constant per gallon dispensed so these emissions drop with fuel economy. Even though emission standards get a maximum spillage rate for fueling stations, it is likely that these emissions will not decrease as fuel economy is improved.

## C.7 Fuel Economy Assumptions

Vehicle fuel economy effects the greenhouse gas emissions and energy use per mile traveled. Figures C-14 and C-15 show estimates of the range in fuel consumption for passenger cars and the corresponding GHG emissions.

[27] Many CNG systems are not equipped with a dedicated electric meter for the compressor. Determining power consumption per scf also requires an alert data collection effort.

**Figure C-12: Uncertain in Marginal NMOG Emissions from RFG3**

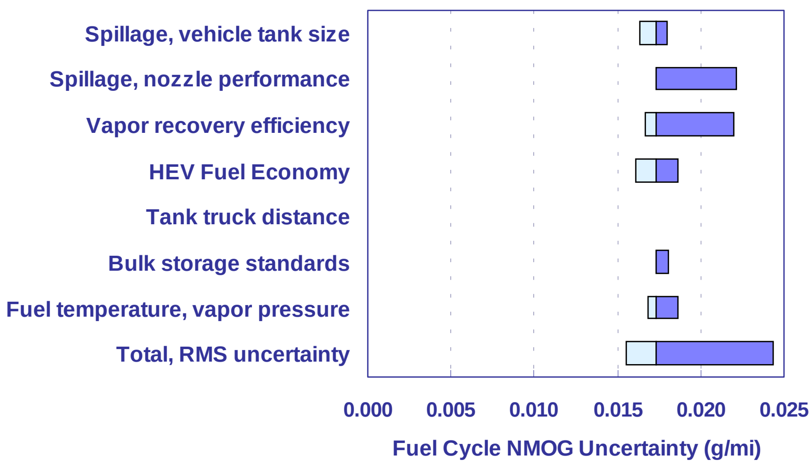



**Figure C-13: Effect of Fuel Economy on Marginal NMOG Emissions from RFG3 Vehicles**

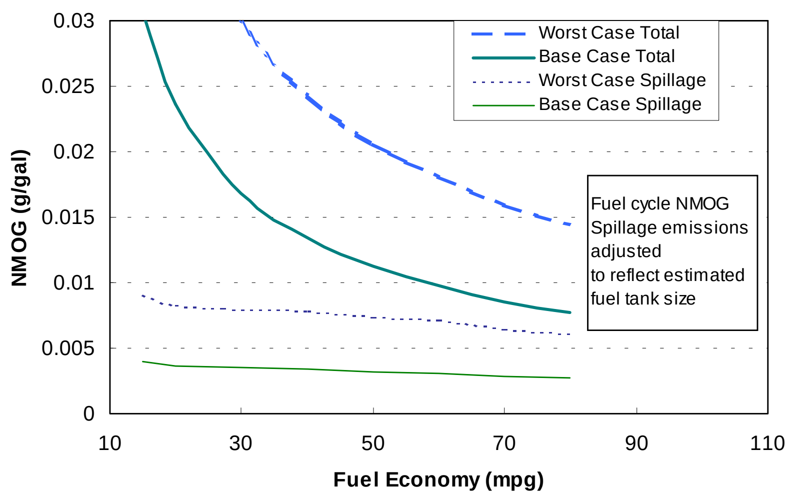


**Figure C-14: Range in fuel economy from passenger cars**

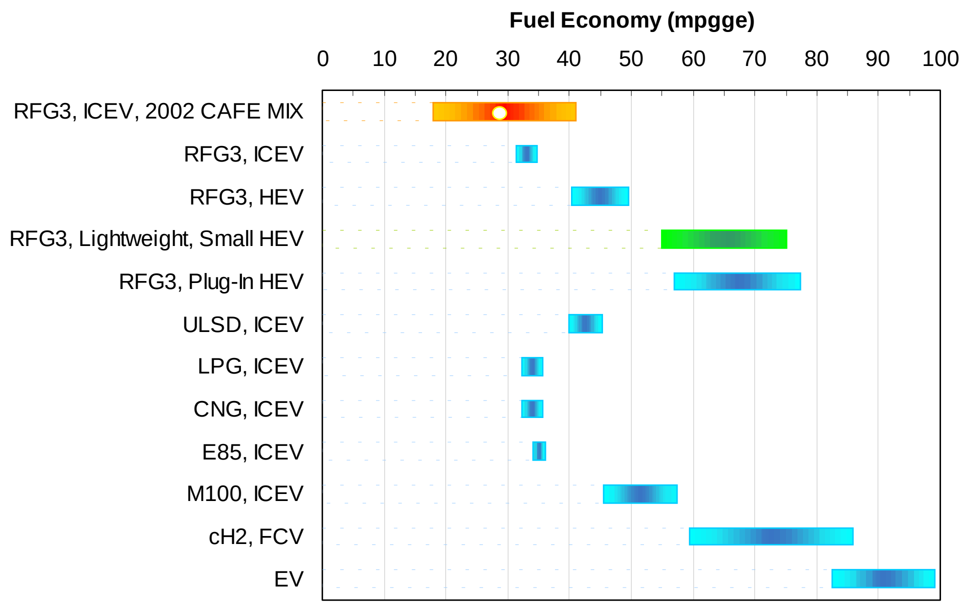
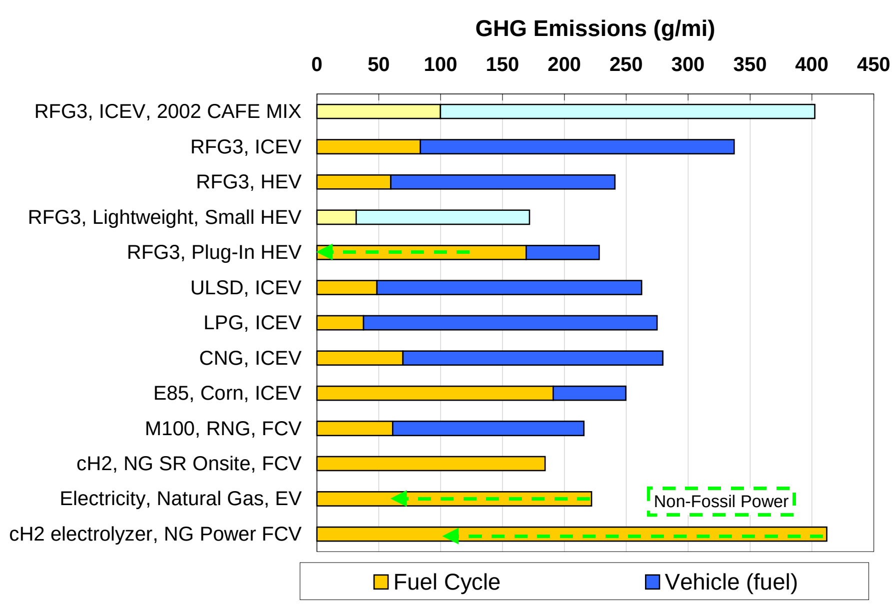



**Figure C-15: Effect of Fuel Economy on Marginal NMOG Emissions from RFG3 Vehicles**



## C.8 Local Vehicle Emissions

Fuel cycle emissions per unit fuel were calculated for the fuels discussed in Section 3. Emissions were calculated for $NO_x$, PM, CO, and NMOG based on transportation, distribution, and other steps in the fuel cycle that result in marginal emissions. Emission estimates were made for each step in the fuel cycle shown below:

- Feedstock transport
- Refinery
- Fuel Transport
- Fuel unloading
- Bulk terminal
- Truck loading
- Truck Spillage
- Truck Exhaust
- Truck Unloading
- Storage Tank Breathing
- Vehicle Working Loss
- Spillage

The emissions are grouped to provide a comparison among different fuels and to allow for the calculation of toxic emissions. The results for the fuels in this study are shown in Tables C-49 through C-52. These tables show the base case estimate that corresponds to compliance with all emission standards. A worst case is also presented which assumes higher rates of vehicle spillage, less control of evaporative losses, and higher $NO_x$ and PM emissions from diesel trucks.

Marginal fuel cycle emissions include combustion exhaust and hydrocarbon losses. Combustion emissions include primarily fuel transportation (and power plant emissions for EVs). The transportation emissions are determined from distances in urban areas and the rest of California combined with emission factors for transportation equipment and other parameters discussed in Section C.6. Combustion emissions include $NO_x$, CO, PM, and NMOG. Various NMOG sources occur throughout the fuel transportation and distribution processes. The emissions correspond to values in Section C.6.

Some second order fuel cycle emissions occur in the SoCAB and these are also included in the fuel cycle analysis. Second order emissions are the emissions associated with producing and distributing the fuel in the fuel cycle. For example, the fuel cycle emissions associated with hauling the diesel fuel used to transport gasoline are calculated.These values represent a very small fraction of the marginal emissions in urban areas.

## Table C-49: $NO_x$ Emissions in California Urban Areas

| Fuel | RFG3 | ULSD | LPG, Petroleum | LPG, Natural Gas | FTD | FTD33 | M100, Natural Gas | LNG | E10 | E65 | E85 | BD2 | B20 | CNG | cH2-NG SR | cH2, NG, LH2 | Electricity, NG | cH2, Electricity, NG |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Units | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | 100 scf | kg | kg | kWh | kg |
| Feedstock Extraction | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Feedstock transport | 0 | 0 | 0.019 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0020 | 0.0034 | 0.0037 | 7.13E-05 | 0.0036 |
| Refinery | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Fuel Transport | 0.025 | 0.025 | 0.000 | 0.090 | 0.023 | 0.025 | 0.024 | 0.017 | 0.029 | 0.066 | 0.079 | 0.028 | 0.053 | 0 | 0 | 0 | 0 | 0 |
| Fuel Unloading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Bulk Terminal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.1832 | 0 | 0 |
| Truck loading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Truck Spillage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Truck Exhaust | 0.011 | 0.012 | 0.009 | 0.009 | 0.011 | 0.012 | 0.011 | 0.008 | 0.011 | 0.011 | 0.011 | 0.012 | 0.012 | 0 | 0 | 0.0058 | 0 | 0 |
| Truck Unloading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 |
| Storage Tank Breathing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vehicle Working Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.057 | 0 | 0 | 0 |
| Spillage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0.0366 | 0.0375 | 0.0278 | 0.0986 | 0.0347 | 0.0365 | 0.0351 | 0.0252 | 0.0398 | 0.0772 | 0.0908 | 0.0403 | 0.066 | 0.0020 | 0.060 | 0.193 | 0.0001 | 0.0036 |

## Table C-50: PM Emissions in California Urban Areas

| Fuel | RFG3 | RFD | LPG | LPG NG | FTD | FTD33 | M100 NG | LNG | E10 | E65 | E85 | BD2 | B20 | CNG | cH2-NG SR | LH2 | Electric | cH2-electricity |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Units | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | 100 scf | kg | kg | kWh | kg |
| Feedstock Extraction | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Feedstock transport | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5.3E-05 | 8.8E-05 | 9.8E-05 | 1.87E-06 | 9.398E-05 |
| Refinery | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.03 | 0.03 | 0.01 | 0.37 |
| Fuel Transport | 0.0017 | 0.0020 | 0.0015 | 0.0013 | 0.0018 | 0.0019 | 0.0018 | 0.0013 | 0.0018 | 0.0021 | 0.0022 | 0.0020 | 0.0020 | 0 | 0 | 0 | 0 | 0 |
| Fuel Unloading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Bulk Terminal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.020 | 0 | 0 |
| Truck loading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Truck Spillage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Truck Exhaust | 0.0004 | 0.0005 | 0.0004 | 0.0004 | 0.0004 | 0.0005 | 0.0004 | 0.0003 | 0.0004 | 0.0004 | 0.0004 | 0.0005 | 0.0005 | 0 | 0 | 0.00023 | 0 | 0 |
| Truck Unloading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage Tank Breathing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vehicle Working Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.019 | 0 | 0 | 0 |
| Spillage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0.0022 | 0.0024 | 0.0018 | 0.0016 | 0.0023 | 0.0024 | 0.0023 | 0.0016 | 0.0022 | 0.0025 | 0.0026 | 0.0025 | 0.0025 | 0.0090 | 0.045 | 0.052 | 0.007 | 0.368 |

## Table C-51:  NMOG Emissions in California Urban Areas

| Fuel | RFG3 | ULSD | LPG | LPG NG | FTD | FTD33 | M100 NG | LNG | E10 | E65 | E85 | BD2 | B20 | CNG | cH2-NG SR | LH2 | Electric | cH2-electricity |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Units | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | 100 scf | kg | kg | kWh | kg |
| Feedstock Extraction | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Feedstock transport | 0 | 0 | 0.0018 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0015 | 0.0026 | 0.0028 | 0.0001 | 0.0027 |
| Refinery | 0 | 0 | 0.03405 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0036 | 0.0106 | 0.0129 | 0.0030 | 0.149 |
| Fuel Transport | 0.002 | 0.002 | 0.000 | 0.010 | 0.002 | 0.002 | 0.002 | 0.001 | 0.003 | 0.007 | 0.009 | 0.003 | 0.006 | 0.0002 | 0.0003 | 0.0003 | 0.0000 | 0.0003 |
| Fuel Unloading | 0.020 | 0.006 | 0.000 | 0.200 | 0.006 | 0.006 | 0.008 | 0.000 | 0.020 | 0.020 | 0.020 | 0.006 | 0.005 | 0 | 0 | 0 | 0 | 0 |
| Bulk Terminal | 0.025 | 0.002 | 0.025 | 0.025 | 0.002 | 0.002 | 0.025 | 0.025 | 0.025 | 0.025 | 0.025 | 0.002 | 0.002 | 0 | 0 | 0.12274 | 0 | 0 |
| Truck loading | 0.068 | 0.013 | 0.208 | 0.208 | 0.012 | 0.012 | 0.016 | 0.005 | 0.068 | 0.064 | 0.062 | 0.013 | 0.013 | 0 | 0 | 0 | 0 | 0 |
| Truck Spillage | 0.004 | 0.004 | 0.007 | 0.007 | 0.004 | 0.004 | 0.004 | 0.007 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0 | 0 | 0 | 0 | 0 |
| Truck Exhaust | 0.003 | 0.003 | 0.002 | 0.002 | 0.003 | 0.003 | 0.003 | 0.002 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0 | 0 | 0.00143 | 0 | 0 |
| Truck Unloading | 0.062 | 0.013 | 0.208 | 0.208 | 0.012 | 0.012 | 0.013 | 0.141 | 0.062 | 0.058 | 0.056 | 0.013 | 0.013 | 0 | 0 | 0 | 0 | 0 |
| Storage Tank Breathing | 0.031 | 0.001 | 0.000 | 0.000 | 0.001 | 0.001 | 0.007 | 0.003 | 0.031 | 0.029 | 0.028 | 0.001 | 0.001 | 0 | 0 | 0 | 0 | 0 |
| Vehicle Working Loss | 0.172 | 0.016 | 0.080 | 0.080 | 0.015 | 0.016 | 0.044 | 0.000 | 0.172 | 0.171 | 0.166 | 0.016 | 0.016 | 0 | 0.0257 | 0 | 0 | 0 |
| Spillage | 0.182 | 0.277 | 0.090 | 0.090 | 0.249 | 0.268 | 0.000 | 0.003 | 0.182 | 0.182 | 0.182 | 0.277 | 0.277 | 0.00335 | 0 | 0 | 0 | 0 |
| Total | 0.569 | 0.337 | 0.655 | 0.830 | 0.305 | 0.326 | 0.122 | 0.187 | 0.569 | 0.563 | 0.555 | 0.337 | 0.339 | 0.01 | 0.04 | 0.14 | 0.00 | 0.15 |

## Table C-52:  CO Emissions in California Urban Areas

| Fuel | RFG3 | RFD | LPG | LPG NG | FTD | FTD33 | M100 NG | LNG | E10 | E65 | E85 | BD2 | B20 | CNG | cH2-NG SR | LH2 | Electric | cH2-electricity |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Units | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | gal | 100 scf | kg | kg | kWh | kg |
| Feedstock Extraction | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Feedstock transport | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.013 | 0.022 | 0.024 | 0.000 | 0.023 |
| Refinery | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.066 | 0.192 | 0.234 | 0.054 | 2.708 |
| Fuel Transport | 0.0033 | 0.0030 | 0.0022 | 0.0167 | 0.0028 | 0.0029 | 0.0028 | 0.0020 | 0.0040 | 0.0116 | 0.0144 | 0.0035 | 0.0085 | 0 | 0 | 0 | 0 | 0 |
| Fuel Unloading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Bulk Terminal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.895 | 0 | 0 |
| Truck loading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Truck Spillage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Truck Exhaust | 0.026 | 0.029 | 0.021 | 0.021 | 0.026 | 0.028 | 0.026 | 0.019 | 0.026 | 0.026 | 0.026 | 0.029 | 0.029 | 0 | 0 | 0.013 | 0 | 0 |
| Truck Unloading | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage Tank Breathing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vehicle Working Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.029 | 0 | 0 | 0 |
| Spillage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 0.029 | 0.032 | 0.023 | 0.037 | 0.029 | 0.031 | 0.029 | 0.021 | 0.030 | 0.038 | 0.041 | 0.032 | 0.037 | 0.079 | 0.243 | 1.166 | 0.054 | 2.731 |

Toxic emissions were determined from the individual fuel cycle NMOG emission sources. The composition of toxic emissions was determined for various sources identified in Section 4. The ratio of toxics to NMOG was used to determine the toxic emissions for each step in the fuel cycle. While many fuel components such as methanol are poisionous or accutely toxic, toxic emisisons in this study only include compounds that are listed by ARB as toxic air contaminants. Toxics that occur from fuels and fuel combustion include:

- Benzene
- 1-3, butadiene
- formaldehyde
- acetaldehyde
- Polycyclic aromatic hydrocarbons (Toxic precursors)
- Diesel particulate

The for each toxic, the sum is determine for each source and the values are presented in the main report.

### C.8.1 Toxic Emissions

Toxic emissions correspond to marginal fuel cycle emission assumptions. Accordingly, the primary source of toxics are associated with tanker truck and rail car distribution, power generation, additional energy consumption related to clean diesel production, and vehicle fueling losses. Sources that are not expected to contribute to marginal emissions in California include average refinery emissions, methanol, FTD, and gas processing plant emissions (which occur outside of California) and coal power plants. Similarly, this study does not evaluate the effect of alternative fuel use on reduced tanker ship traffic and the potential for accidental releases. LFG and biomass based on ethanol plants could generally result in a reduction in toxic emissions depending on the source of waste feedstocks. The numerous feedstock alternatives are not evaluated here. An example is presented in a study on ethanol production (Perez 2001). Using feedstocks such as agricultural residue which would otherwise be burned results in a significant reduction in particulate emissions and potentially a reduction in toxics also.

California Assembly Bill AB 1807 created a comprehensive program to address adverse public health impacts from emissions of toxic substances to ambient air. Toxic air contaminants are an air pollutant that may cause or contribute to an increase in mortality or an increase in serious illness. A series of compounds were identified by ARB as toxic air contaminants, five of which are related to the combustion of fuels. They are 1,3-butadiene, benzene, formaldehyde, acetaldehyde, and diesel particulates.

Toxic emissions and toxic precursors were estimated for engine exhaust, fuel, fuel vapor, natural gas, liquid petroleum gas, refinery emissions, pipeline compression engine emissions, and power plant emissions. They are given in terms of milligrams of toxics per gram of unit of fuel in Table C-63.

**Table C-53: Toxic Emissions Levels**

| Compound | RFG3 | ULSD | LPG | LPG NG | FTD | FTD33 | M100 NG | LNG | E10 | E65 | E85 | BD2 | B20 | CNG | cH2-NG SR | LH2 | Electric | cH2-electricity |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Units | gal | gal | gal | gal | gal | gal | gal | gal | gal | Gal | gal | gal | gal | 100 scf | kg | kg | kWh | kg |
| Benzene | 4.82 | 0.13 | 0.10 | 0.30 | 0.12 | 0.12 | 0.12 | 0.08 | 4.54 | 2.57 | 1.44 | 0.13 | 0.21 | 0.00 | 0.12 | 0.110 | 0.0135 | 0.65 |
| 1,3- Butadiene | 0.01 | 0.01 | 0.01 | 0.03 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.02 | 0.03 | 0.01 | 0.02 | 0.00 | 0.00 | 0.010 | 0.0001 | 0.01 |
| Formaldehyde | 0.88 | 0.90 | 0.69 | 2.15 | 0.83 | 0.88 | 0.84 | 0.60 | 0.95 | 1.74 | 2.03 | 0.96 | 1.49 | 0.02 | 0.33 | 0.793 | 0.0405 | 1.95 |
| Acetaldehyde | 0.44 | 0.45 | 0.34 | 1.07 | 0.41 | 0.44 | 0.42 | 0.30 | 0.47 | 0.87 | 1.01 | 0.48 | 0.74 | 0.00 | 0.00 | 0.394 | 0.0006 | 0.03 |
| Total | 6.14 | 1.49 | 1.14 | 3.55 | 1.37 | 1.45 | 1.39 | 0.99 | 5.97 | 5.20 | 4.50 | 1.59 | 2.45 | 0.02 | 0.45 | 1.308 | 0.0547 | 2.64 |

## C.9 Energy Inputs and Greenhouse Gas Emissions

GHG emissions were determined from energy inputs to the fuel cycle. These efficiency values are input into GREET 1.6, the Argonne National Laboratory model, which, among other things, calculates GHG emissions for fuels. Fuels not included in the GREET model were calculated in a similar fashion using an in-house model.

Unlike the local emissions presented in this report, which are calculated from the perspective of an individual exposed in one location, GHG emissions are calculated in a manner that accounts for all global emissions from the entire fuel cycle process. For biomass fuels, the carbon dioxide credited to the carbon in the biomass is not counted toward the total GHG emissions since these are a short term removal and replacement of carbon from the atmosphere.

Methane and $N_2O$ are calculated based on known emissions from gasoline light duty vehicles and GREET assumptions of the percentage of these gases produced by other vehicles and fuels. No $N_2O$ or $CH_4$ emissions factors are used in the calculation of GHGs. The study uses standard 100 year Global Warming Potential values of 23 for $CH_4$ and 296 for $N_2O$ to convert to a $CO_2$ equivalent value, the figure of merit in the tables and figures. Recent findings that radiative forcing of criteria pollutant aerosols may cause negative warming feedback in the atmosphere (Jacobson, 2001) have led to some new thinking on greenhouse gas effects on global warming. Nevertheless, this study has followed the most standard method of greenhouse gas calculation set by the Intergovernmental Panel on Climate Change.

Fuel cycle emissions were calculated using GREET 1.6 with assumptions that reflect long term alternative fuel production and imported gasoline and diesel usage in California GHG emissions from the vehicle cycle include $CO_2$ from combustion as well as $N_2O$ and $CH_4$ emissions.

These fuels include the following:

- CARB OB (blending componenet for RFG3)
- RFD
- Fischer Tropsch Diesel
- Electric Power (national and California)
- Ethanol from corn
- Methanol from natural gas

- LPG
- LNG
- Naphtha
- Biomass Feedstock
- Natural Gass Feedstock (uncompressed)
- Biodiesel

Fuel cycle emissions are then determined for the fuels that are blended or processed from these primary fuels. Fuels that are simple blends include E85, E10, RFG3 (CARBOB plus 5.7 weight percent ethanol), biodiesel, and blended FTD/ diesel. Fuel cycle emissions are also calculated for fuels that require a combination of primary fuels for their production. These fuels include CNG, ethanol from biomass, compressed hydrogen from steam reforming, and compressed hydrogen from electrolysis. In order to calculate ethanol from biomass using the in-house model, it had to be considered a secondary fuel that uses primary fuel inputs in the fuel cycle processes.

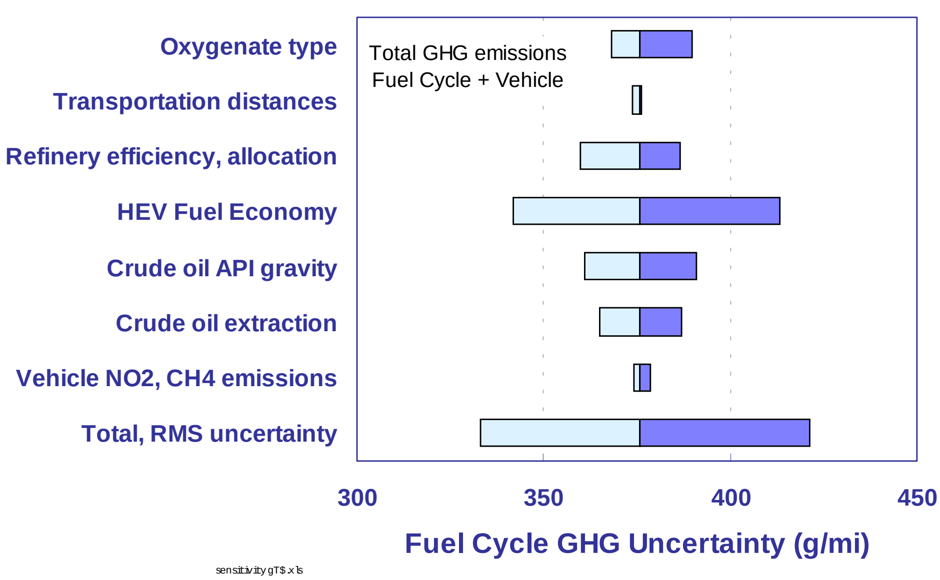
Table C-54 illustrates the energy inputs associated with primary fuels and the vehicle fuels considered in this study. (biodiesel to be added). They are shown in unit of energy input per unit of energy in the finished fuel. All fuels have 1 MJ/MJ of energy allocated to the fuel since there is 1 MJ of energy in the unit of fuel that provides 1 MJ of energy toward vehicle propulsion. The additional energy ratio accounts for the additional energy required to produce and transport 1 MJ of fuel. These energy-based figures of merit are better measures of the fuel cycle energy requirements and associated GHG emissions than per mile or per kilometer values because they remove the vehicle efficiency variability.

Figure C-19 illustrates the key parameters that affect GHG emissions. The GHG emissions associated with gasoline vehicles is relatively well defined. About 70 percent of the GHG emissions correspond to $CO_2$ from carbon in the fuel. The emissions per mile are less certain as they depend upon the vehicle fuel economy. Vehicle fuel economy has the most significant impact on GHG emissions. The uncertainty represented in Figure C-19 represents the variability for a single type of vehicle and not the range fuel economy that can be expected for all vehicle classes. Other parameters that affect GHG emissions are also shown. The properties of crude oil correspond to the carbon content of the fuel and related $CO_2$ emissions. Interstingly, Figure C-19 illustrates that transportation distances and the type of oxygenate represent relatively small uncertainties when translated to GHG emissions.

**Table C-54: Fuel Cycle Energy Inputs and GHG Emissions**

| | Emissions | | ENERGY USE | | | | | |
|---|---|---|---|---|---|---|---|---|
| | GHG g/MJ | | Vehicle Fuel Energy (MJ/MJ) | | | Fuel Chain Energy (MJ/MJ) | | |
| Fuel | Vehicle Cycle | Fuel Cycle | Petroleum | Other Fossil Fuel | Non Fossil Fuel | Petroleum | Other Fossil Fuel | Non Fossil Fuel |
| RFG3, Petroleum, ICEV | 70.57 | 24.45 | 0.96 | 0.00 | 0.04 | 0.13 | 0.18 | 0.02 |
| ULSD, Petroleum, ICEV | 76.62 | 17.38 | 1.00 | 0.00 | 0.00 | 0.09 | 0.12 | 0.00 |
| LPG, Petroleum, ICEV | 67.81 | 10.81 | 1.00 | 0.00 | 0.00 | 0.03 | 0.07 | 0.01 |
| LPG, Natural Gas, ICEV | 67.61 | 10.81 | 0.00 | 1.00 | 0.00 | 0.03 | 0.07 | 0.01 |
| FTD, RNG, ICEV | 72.25 | 31.17 | 0.00 | 1.00 | 0.00 | 0.02 | 0.65 | 0.00 |
| M100, RNG, FCV | 68.70 | 26.26 | 0.00 | 1.00 | 0.00 | 0.03 | 0.52 | 0.00 |
| LNG, RNG, ICEV | 61.96 | 24.09 | 0.00 | 1.00 | 0.00 | 0.01 | 0.31 | 0.00 |
| LNG, US NG, ICEV | 61.96 | 22.44 | 0.00 | 1.00 | 0.00 | 0.00 | 0.20 | 0.00 |
| E100, Corn, ICEV | 2.37 | 64.93 | 0.00 | 0.00 | 1.00 | 0.09 | 0.52 | 0.74 |
| E100, Biomass, ICEV | 2.37 | 15.60 | 0.00 | 0.00 | 1.00 | 0.13 | 0.06 | 0.35 |
| Biodiesel, ICEV | 7.24 | 33.39 | 1.00 | 0.00 | 0.00 | 0.08 | 0.29 | 0.01 |
| CNG, Natural Gas, ICEV | 60.05 | 19.90 | 0.00 | 1.00 | 0.00 | 0.00 | 0.17 | 0.00 |
| cH2, NG SR Onsite, FCV | 0.00 | 112.70 | 0.00 | 1.00 | 0.00 | 0.01 | 0.70 | 0.00 |
| cH2, NG SR LH2, FCV | 0.00 | 143.69 | 0.00 | 1.00 | 0.00 | 0.01 | 1.16 | 0.00 |
| Electricity, Natural Gas, EV | 0.00 | 178.74 | 0.01 | 0.99 | 0.00 | 0.01 | 1.71 | 0.00 |
| cH2, electrolyzer, NG Power FCV | 0.00 | 251.74 | 0.01 | 0.99 | 0.00 | 0.02 | 2.81 | 0.00 |

**Figure C-16. Key Parameters that Affect GHG Emissions**



## C.10 Source of California Fuels

In the early 1990s California policy makers incorporated the “zero emission vehicles” into attainment goals for air quality. Public discussion at the time raised the point that some vehicles which have no emissions “at the tailpipe” (e.g., battery-powered vehicles that have no tailpipe) nonetheless were not “zero emission” because their ultimate source of power, such as an electric generating plant, created its own fuel cycle pollution.

Methodologies were very quickly developed by stakeholders to try to quantify the “total emissions” of a vehicle on a grams-per-mile basis. Very quickly, perplexing issues developed. If a battery is charged from a power plant in Los Angeles, the comparison with a gasoline vehicle is very straightforward. But if Los Angeles is consuming a generic mix of electricity from a power grid supplied by several states, then emissions generated out-of-state might not be relevant to considering local attainment goals. There is no way to know if electric vehicles are drawing their power from out-of-state or from within the attainment area. One way to cope with this problem is to subtract out-of-state upstream pollution from the grams-per-mile calculations. These seemingly arcane considerations can have substantive impacts on the grams-per-mile figure that is used as an index in policy making. They therefore can have considerable importance.

The principle of fuel cycle emissions is easy to grasp, but in practice these quantification exercises are quite complicated. Some stakeholders argued that if electric vehicle emissions were to be quantified with regard to their “fuel cycle emissions,” then gasoline-powered vehicles, which have traditionally been regulated “at the tailpipe,” should also be subjected to the same methodology. But “fuel cycle emissions” quantification for a gasoline vehicle has as many sources of potential variation as vehicles that charge off a regional power grid. Indeed, virtually every known conventional or alternative fuel technology (i.e., gasoline, diesel, CNG, electric, electric hybrid, methanol, etc.) poses a considerable quantification challenge when the “full fuel cycle” is taken into account.

The question of “where California gets its fuel” is important to the full fuel cycle emissions quantification. Under procedures similar to those used for quantifying electric vehicle upstream emissions, California gasoline and diesel fuel brought in from abroad should not have refinery emissions included in its “grams per mile” tally. However, imported refined products would be subject to various alternative quantification methods relating to offloading at port, spillage, evaporation, and distribution.

### Rest-of-the-World: Foreign Imports of CA-RFG

During the gasoline price spike of 1997 modest downward pressure on California’s market was exerted by contracts for CA-RFG from such distant sources as Finland (Neste, a company that primarily exports for world markets), the Caribbean (Amerada Hess), and Asia. California’s “imports” of refined product are currently about 5 percent of the market, but does not come from foreign suppliers. CA-RFG makes its way into some of the more difficult-to-reach parts of Northern California from refineries in the Midwest.

Most large-scale sophisticated refineries in the U.S. and worldwide have the ability to make CA-RFG. They do not face the significant engineering problems faced by the California refineries. The California- specific problems stem from the need to make the entire spectrum of refinery products conform to strict environmental standards. The more volatile lighter aromatics must be reduced, broken down, or otherwise eliminated from the production process.

Many foreign refiners face no such restriction. They can respond to high prices in California by running batches of CA-RFG and putting many of the undesirable components, which they have removed from the CA-RFG, into their other fuels. A typical world-class refinery could in theory produce as much of 20 percent of its output as CA-RFG. Because they face few or no local fuel content regulations, they can run off a premium grade environmental gasoline by diverting unwanted elements into an increased-volatility gasoline.

In theory, therefore, a number of foreign refineries can "skim" the California market during high price episodes. In practice, this is difficult and risky, because sometimes the California-bound product reaches its destination after the price spike has passed. Neste has testified that trying to enter the California market during a refinery or equipment-related price spike is extremely risky and has not been particularly profitable in the past.

Nonetheless, were a sustained price increase to occur in California, some of these refineries might find systematic participation in the California market to be attractive. The specific form of market intervention cannot be ascertained. Such foreign suppliers might simply try to act as spot suppliers to the market. More likely, they would seek long-term contracts with major California companies. Alternatively, major California companies might approach them for additional product. The California companies could even buy participation in selected foreign operations to forge a closer relationship for long-term supply purposes.

The ability of out-of-state refiners to make up to 20 percent CA-RFG may raise a policy question of fairness. Is California in effect using its wealth to "export" pollution by inciting refiners to ship an environmental premium grade to the state, while a more volatile product was marketed elsewhere? The question cannot be answered from general principles. If, for example, it were certain that the less-desirable product stream was being marketed in notorious high-pollution cities, for example, the implications would be troubling. But the less desirable product could also be marketed at a discount and used in agricultural or other commercial applications in countries with few pollution problems. This might actually help their economies while doing no or limited environmental harm.

The production of increased-volatility product as a corollary of producing CA-RFG could well be a short- to medium-term occurrence. It might resurface occasionally during price spikes caused by malfunctions in refineries or the distribution network. In the long-term, the emergence of large-scale markets where environmental regulations are in effect, such as in the United States and Western Europe, makes it likely that worldwide some "designer refineries" will specialize in "boutique gasoline" to meet the needs of countries or areas that have enacted stringent fuel requirements. There is already some concern in Arizona, for example, that CA-RFG does not meet the specific attainment goals of Phoenix and Tucson.

The rest-of-the-world permutations would therefore look something like this:

A. Incremental and more frequent participation of foreign refiners in CA markets, implying a gradually increasing flow of foreign refined imports in California's total fuel mix. In the early phases these foreign refiners would be marketing CA-RFG as a premium export grade and simultaneously making a lower-grade fuel to less stringently regulated markets.

B. The emergence of "designer refineries" tailored specifically to the needs of markets that have enacted stringent environmental requirements. Conventional refineries not adhering to these production practices would produce environmental premium grades only on an occasional basis in response to specific price spikes. Several of the people interviewed for this report suggested that the spread of CA-RFG and other "green" fuel formulations is an industry-wild card possibility that could have the effect of making CA-RFG more available, nationally and internationally, than has been the case until now.

These permutations are also compatible with the participation of Texas in the California market.

Three additional points should be mentioned in this section. First, policy makers may have concerns about the equity issue associated with the marketing, elsewhere in the world, of a "lower-grade gasoline" that is a by-product of making CA-RFG. This concern might make them lean toward expediting or expanding permitting for in-state refining. Second, Caribbean ethanol producers are completely exempted from U.S. tariffs that apply to other world ethanol producers (Mexico and Canada have special, lower tariffs on ethanol). This tariff exemption raises the possibility that Caribbean refineries will play a role in market scenarios where the MTBE phase-out results in increased ethanol use. Third, from the point of view of emissions quantification, permutations that envision increased foreign imports will have associated emissions from increased docking and unloading activities.

### Puget Sound Refineries

The Puget Sound refinery operations (Shell at Anacortes, ARCO at Cherry Point) have recently been able to participate in the production of CA-RFG. Regardless of whether their feedstock comes from Alaska or Asia, these refineries are part of a regional air-inventory that is more forgiving than California's, and one person interviewed considered it much easier to get permitting to expand production in these areas than in California. These refiners are already attracted to a limited degree, to the higher priced California market. Expanding their production capability, as with the Gulf Coast, could prove an attractive option to increase long-term supplies of fuel.

### Expansion of California Refining

It is unlikely that new refineries will be built in California. In fact, from 1985 to 1995, ten California refineries closed, resulting in a 20 percent reduction in refining capacity. Further refinery closures are expected for small refineries with capacities of less than 50,000 bbl/day. The cost of complying with environmental regulations and low product prices will continue to make it difficult to continue operating older, less efficient refineries.

The Western States Petroleum Association (WSPA) has circulated an op-ed article that calls for "modernizing [petroleum fuels] infrastructure to make it more efficient," the need to favor large scale investments, and the need to expedite the siting, permitting and construction of "plants, pipeline terminals, and service stations."

This general text is consistent with the various options already discussed above. In an interview, the author suggested that in-state expansion of refining will be the single biggest source of CA-RFG in the years to come. Almost all other options, in his view, presented significant cost disadvantages relative to what the California refineries could do within the "footprint" of their existing physical plant. California refineries would process increasing crude imports (whether from abroad, or from the Gulf Coast, or other sources).

This would be possible because a "regulatory bubble" over refining operations allows trading of reductions from older types of equipment to operations designed to increase throughput. Though the specific details were not discussed, there are apparently a number of technological advances of the past five to ten years that suggest major control opportunities. The author also felt that the regulatory authorities would be amenable to equipment upgrades. In a nutshell, CA refining should be able to meet increasing levels of demand with constant or even declining total emissions.

### Assumption for California Gasoline Supply

Since the baseline scenario in the Energy Commission's study of petroleum reduction options is a steady growth in demand climbing to over 30 billion gallons of demand by 2050, it seems prudent to assign most of the emissions associated with reductions in petroleum usage to a reduction in imports. Much of the incremental local emissions over today's consumption will occur outside of California. A modest amount of expansion in California refinery capacity is expected to occur but only the most aggressive petroleum reduction options would result in this capacity not being fully utilized. Demand from Nevada and Arizona would also provide a market for California refineries. Therefore, for the demand assumptions developed in the California Energy Commission study on reduction of gasoline and diesel demand (CEC 2002), refinery output and corresponding emissions will not be affected by a reduction in fuel usage.

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## C.12 List of Terms and Abbreviations

| | |
|---|---|
| AP-42 | EPA document on emission factors |
| atm | 1 atmosphere = 14.7 psi |
| EMFAC | ARB model for determining vehicle g/mi emissions |
| API | American Petroleum Institute |
| ARB | California Air Resources Board |
| bbl | barrel of crude oil (42 gal) |
| Bcf | billion standard cubic feet |
| BD | biodiesel |
| bhp-hr | brake horsepower hour (dynamometer measurement) |
| Btu | British thermal unit = 1.055 kJ |
| bsfc | brake specific fuel consumption |
| CA | California |
| CARBOB | California Reformulated Gasoline Blendstocks for Oxygenate Blending |
| CEC | California Energy Commission |
| $cH_2$ | compressed hydrogen[28] |
| CNG | compressed natural gas |
| $CH_4$ | methane |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| DOE | United States Department of Energy |
| DWT | dead weight ton |
| E100 | ethanol, 100 percent with no blending components |
| EMA | Engine Manufacturers Association |
| EMFAC | ARB vehicle emissions factor model |
| EVs | electric vehicles |
| FCC | fluid catalytic cracker |
| FE | Fuel economy |
| FFV | flexible fuel vehicle |
| FTD | Fischer Tropsch diesel |
| GWh | gigaWatt hour = 1,000,000 kWh |
| GRI | Gas Research Institute |
| GVW | gross vehicle weight |
| GWP | global warming potential |
| HHV | higher heating value of fuel or feedstock |
| hp-hr | shaft horsepower hour |
| IC | internal combustion |
| ICEV | IC engine vehicle |
| J | Joule |
| kg | kilogram |
| kJ | kilo Joule |
| kWh | kilo-Watt hour = 3.6 MJ = 3,412 Btu |
| kn | nautical mile, 2000 yards |

[28] The lower case c is used to prevent confusion with hydrocarbon radicals.

| | |
|---|---|
| lb | pound mass = 453.5 g |
| LHV | lower heating value, HHV less heat of vaporization of water vapor in combustion products |
| LH2 | liquid hydrogen |
| LPG | liquefied petroleum gas |
| MJ | Mega Joule = 3.6 kWh |
| $H_2$ | hydrogen |
| g | gram |
| gal | gallon = 3.785 Liter |
| g/bhp-hr | grams per brake horsepower-hour |
| MWh | megaWatt hour |
| mi | mile |
| LNG | liquefied natural gas |
| M100 | methanol, 100 percent with no blending components |
| MMBtu | million Btu |
| MMscf | million scf |
| MTBE | methyl tertiary butyl ether |
| mpg | miles per gallon |
| MW | molecular weight |
| NG | natural gas |
| NGV | natural gas vehicle |
| NMOG | non-methane organic gases |
| $NO_x$ | oxides of nitrogen |
| NREL | National Renewable Energy Laboratory |
| NSPS | new source performance standards |
| $O_3$ | ozone |
| OEM | original equipment manufacturer |
| psi | pressure, $lb/in^2$, 14.7 psi = 1 atm |
| RECLAIM | Regional Clean Air Incentive Market |
| RFG3 | reformulated gasoline, current California requirement |
| RNG | remote natural gas, produced outside North America |
| ROW | rest of world |
| RVP | Reid vapor pressure |
| SoCAB | South Coast Air Basin |
| SCAQMD | South Coast Air Quality Management District |
| SCE | Southern California Edison |
| scf | standard cubic feet of gas, at 60°F and 1 atm |
| SCR | selective catalytic reduction |
| scfm | standard cubic feet per minute |
| $SO_x$ | oxides of sulfur |
| SR | steam reformer |
| SRWC | short rotation woody crops |
| t/d | tons/day |
| TEOR | thermally enhanced oil recovery |
| THC | total hydrocarbons |
| ton | United States short ton, 2000 lb |

| | |
|---|---|
| TOG | total organic gases |
| TVP | true vapor pressure |
| UG | underground |
| U.S. EPA | United States Environmental Protection Agency |
| ullage | liquid fuel tank vapor space |
| $V_e$ | equilibrium vapor |

## Appendix D. Supplemental Emissions Reduction Results

In addition to the results presented in Section 2, additional results of the emissions reduction analysis are presented here. Figures D-1 through D-6 are for the Improved Fuel Economy Options (Group 1A).

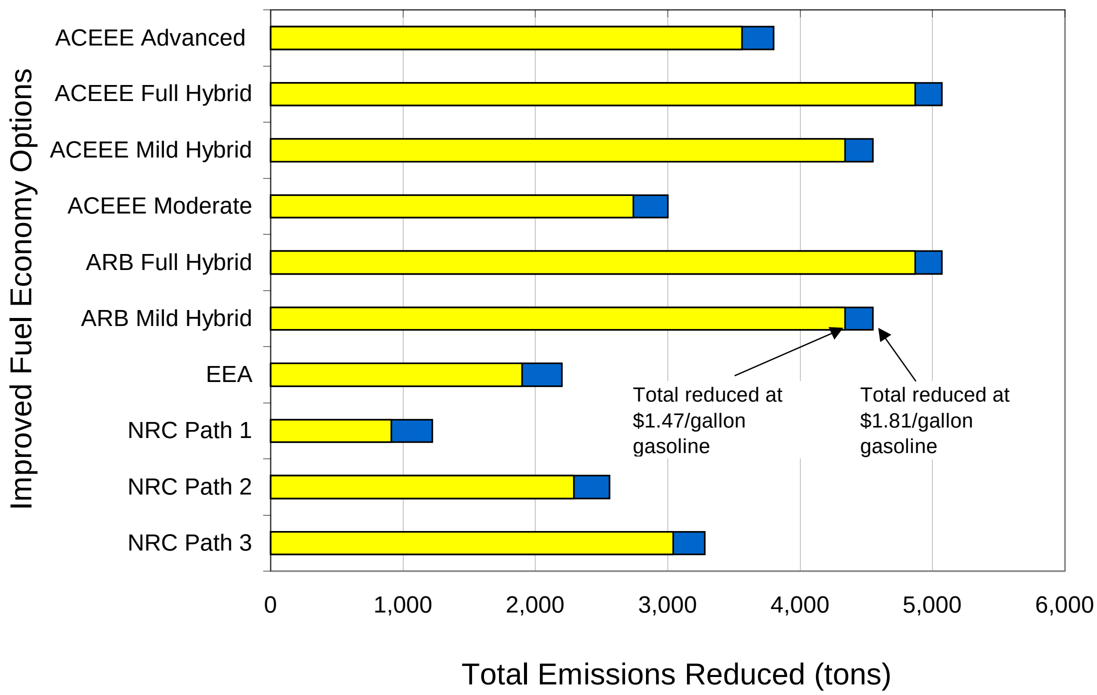


**Figure D-1. Group 1A Criteria Pollutant Emissions Reduction (2020)**

The darker values corresponding to a range of retail gasoline prices ($1.47/gallon to $1.81/gallon gasoline).

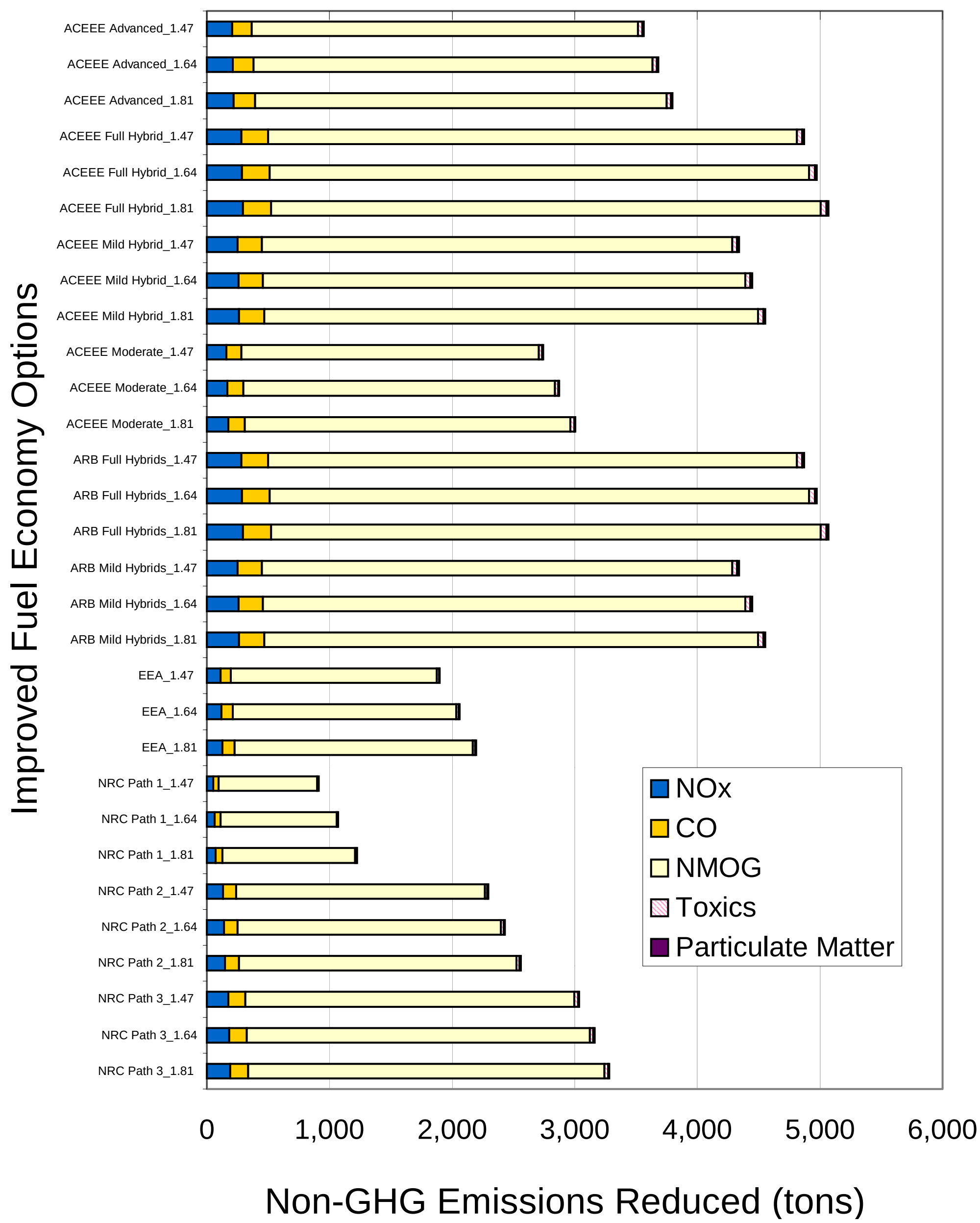


**Figure D-2.  Group 1A Criteria Pollutant Emission Reduction (2020)**

The relative distribution of criteria pollutant species is the same for all years and all Group 1A options.  The suffix "_1.XX" in the option name refers to the assumed retail price of gasoline for that option.  For example, "ACEEE Advanced_1.47" refers to the ACEE Advanced Improved Fuel Economy option where the retail price of gasoline is $1.47/gallon.

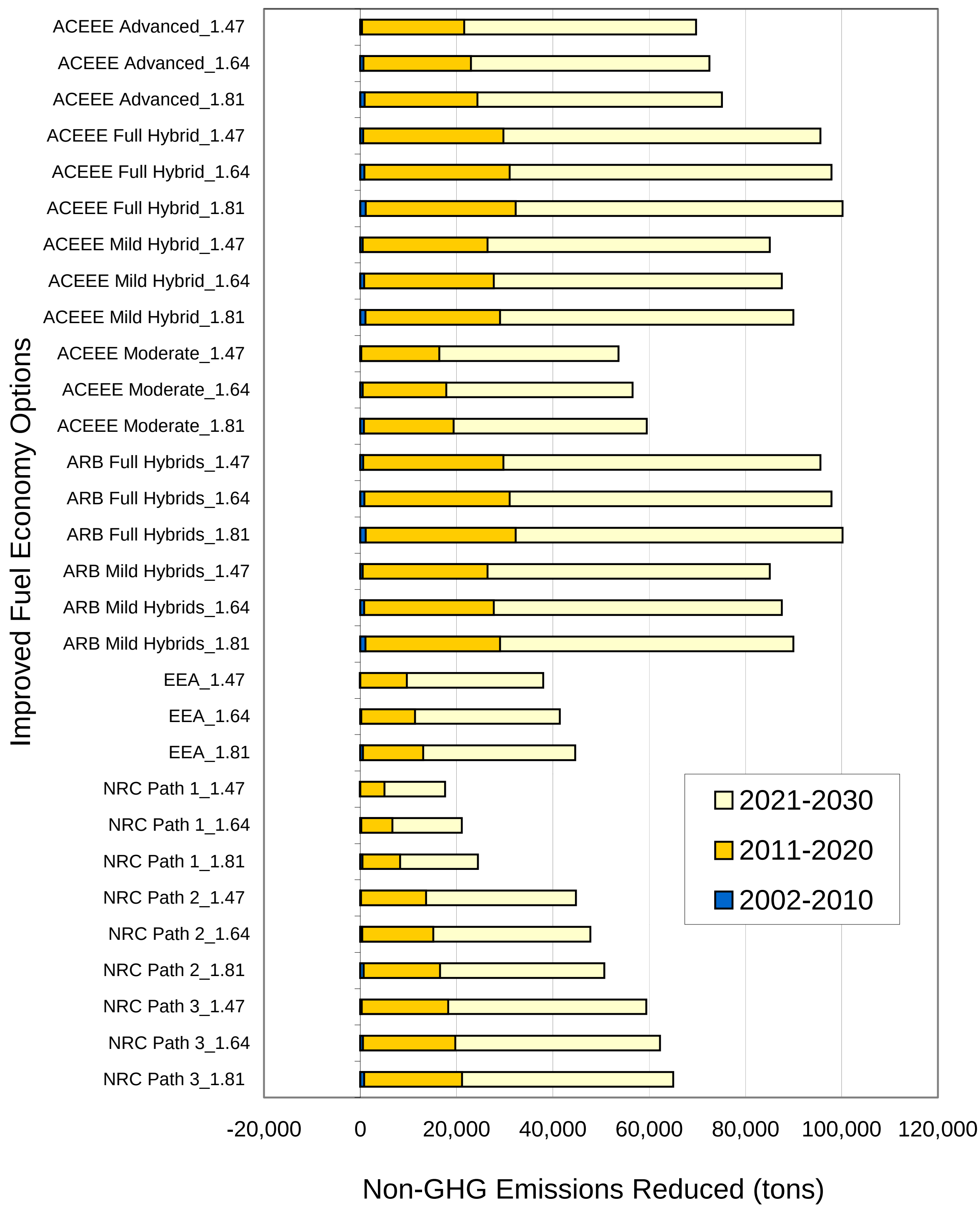


**Figure D-3. Group 1A Cumulative Criteria Pollutant Emissions Reduction for 2002-2030**

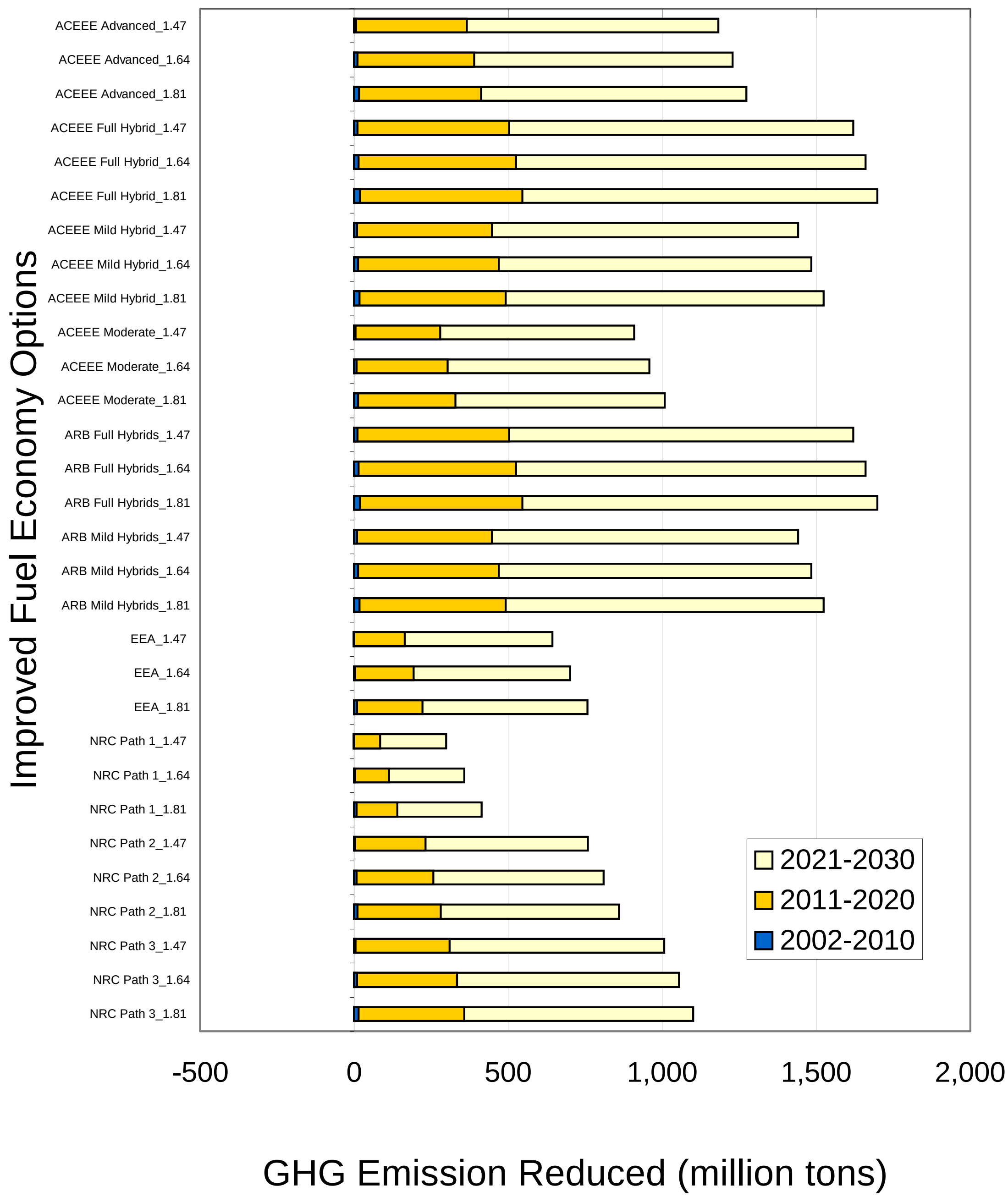


**Figure D-4. Group 1A Cumulative GHG Emission reduction for 2002-2030**

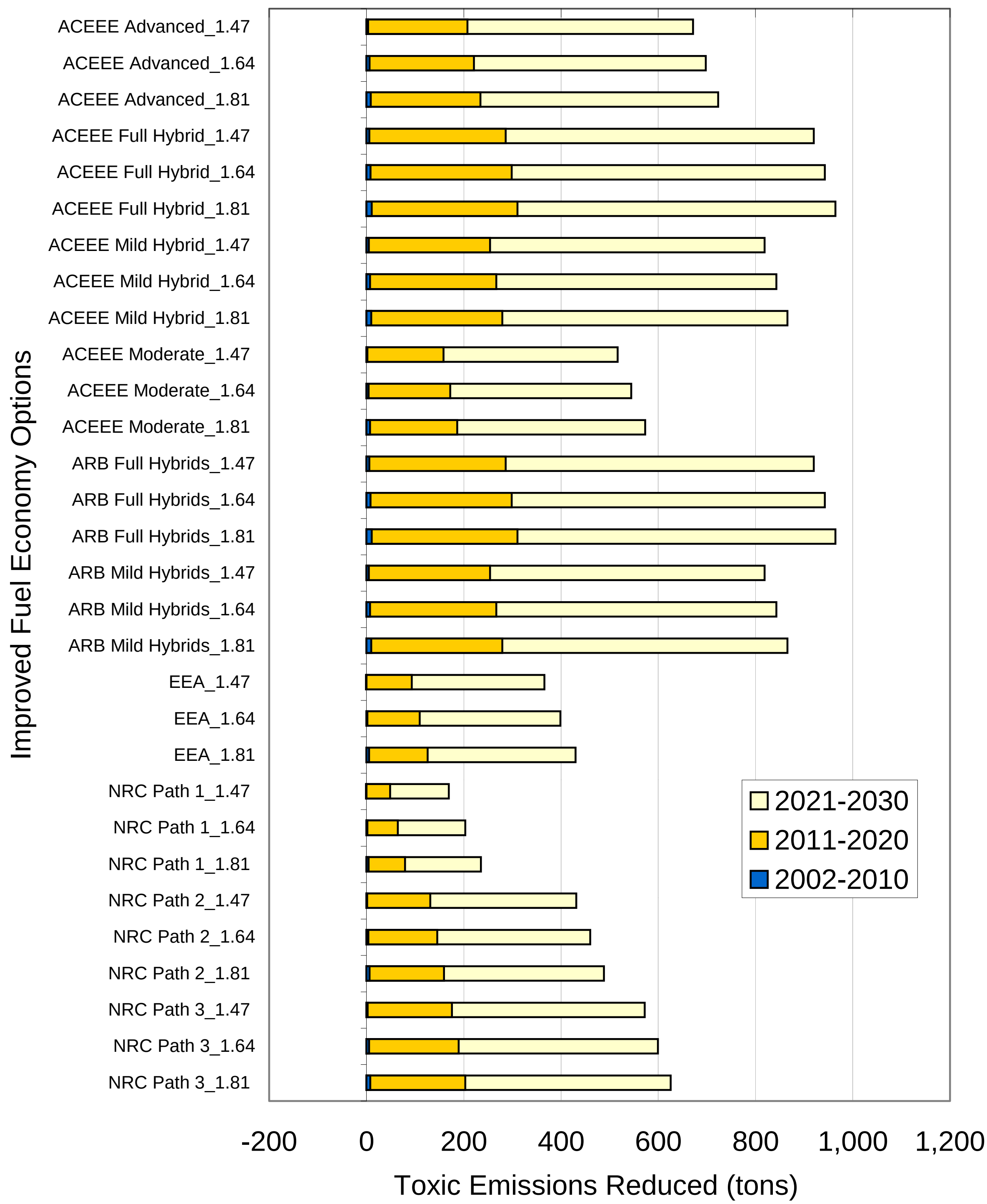


**Figure D-5. Group 1A Cumulative Toxics Emissions Reduction for 2002-2030**

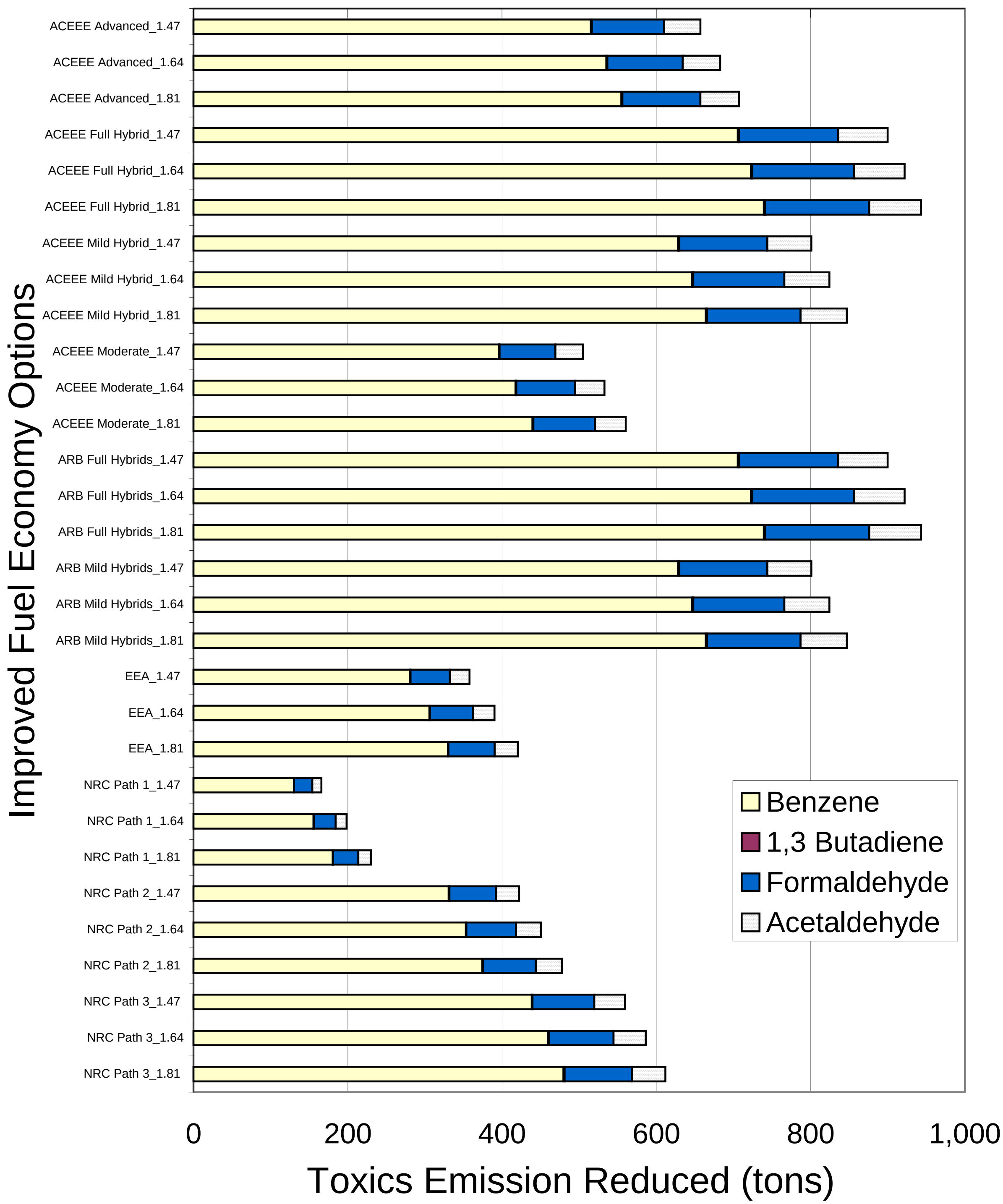
Improved Fuel Economy Options
ACEEE Advanced_1.47
ACEEE Advanced_1.64
ACEEE Advanced_1.81
ACEEE Full Hybrid_1.47
ACEEE Full Hybrid_1.64
ACEEE Full Hybrid_1.81
ACEEE Mild Hybrid_1.47
ACEEE Mild Hybrid_1.64
ACEEE Mild Hybrid_1.81
ACEEE Moderate_1.47
ACEEE Moderate_1.64
ACEEE Moderate_1.81
ARB Full Hybrids_1.47
ARB Full Hybrids_1.64
ARB Full Hybrids_1.81
ARB Mild Hybrids_1.47
ARB Mild Hybrids_1.64
ARB Mild Hybrids_1.81
EEA_1.47
EEA_1.64
EEA_1.81
NRC Path 1_1.47
NRC Path 1_1.64
NRC Path 1_1.81
NRC Path 2_1.47
NRC Path 2_1.64
NRC Path 2_1.81
NRC Path 3_1.47
NRC Path 3_1.64
NRC Path 3_1.81
Benzene
1,3 Butadiene
Formaldehyde
Acetaldehyde
0
200
400
600
800
1,000
Toxics Emission Reduced (tons)

**Figure D-6. Group 1A Speciated Toxics Emissions Reduction from 2002-2030**

The Other Fuel Efficiency options (Group 1B through 1E) are presented in Figures D-7 through D-11. Note that even the largest reductions out of these options are much smaller than the Group 1A options.

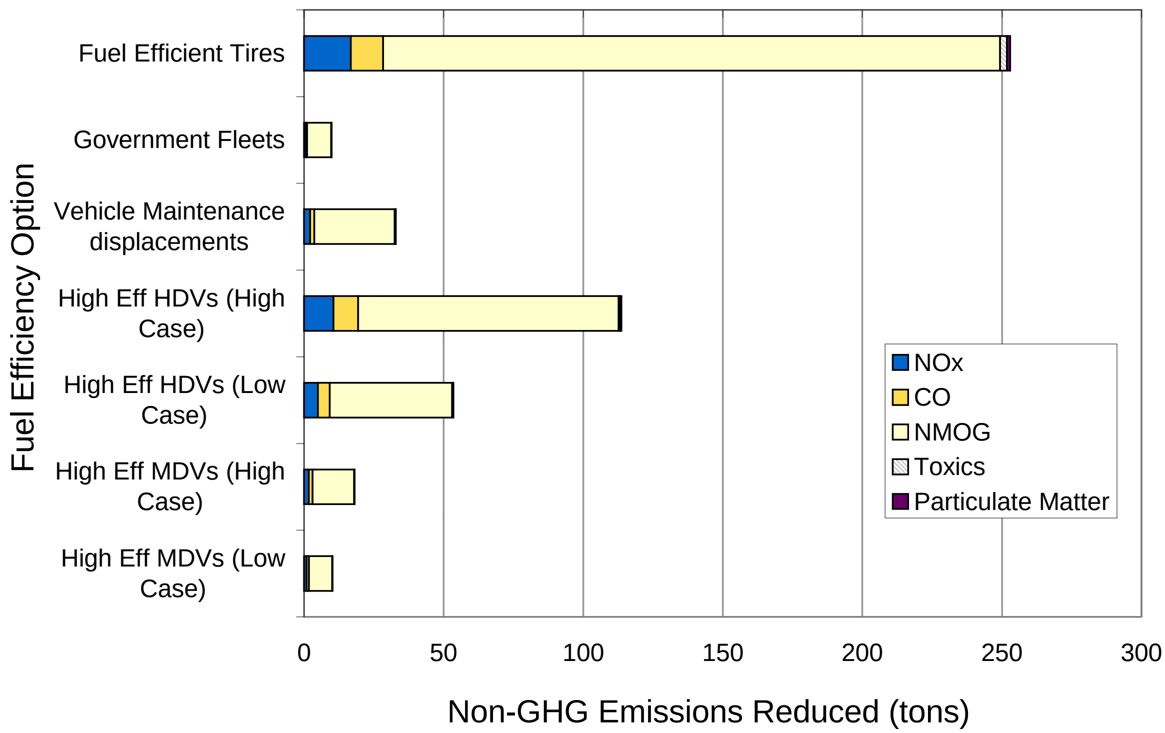


**Figure D-7. Group 1B-E Criteria Pollutant Emission Reduction in 2020**

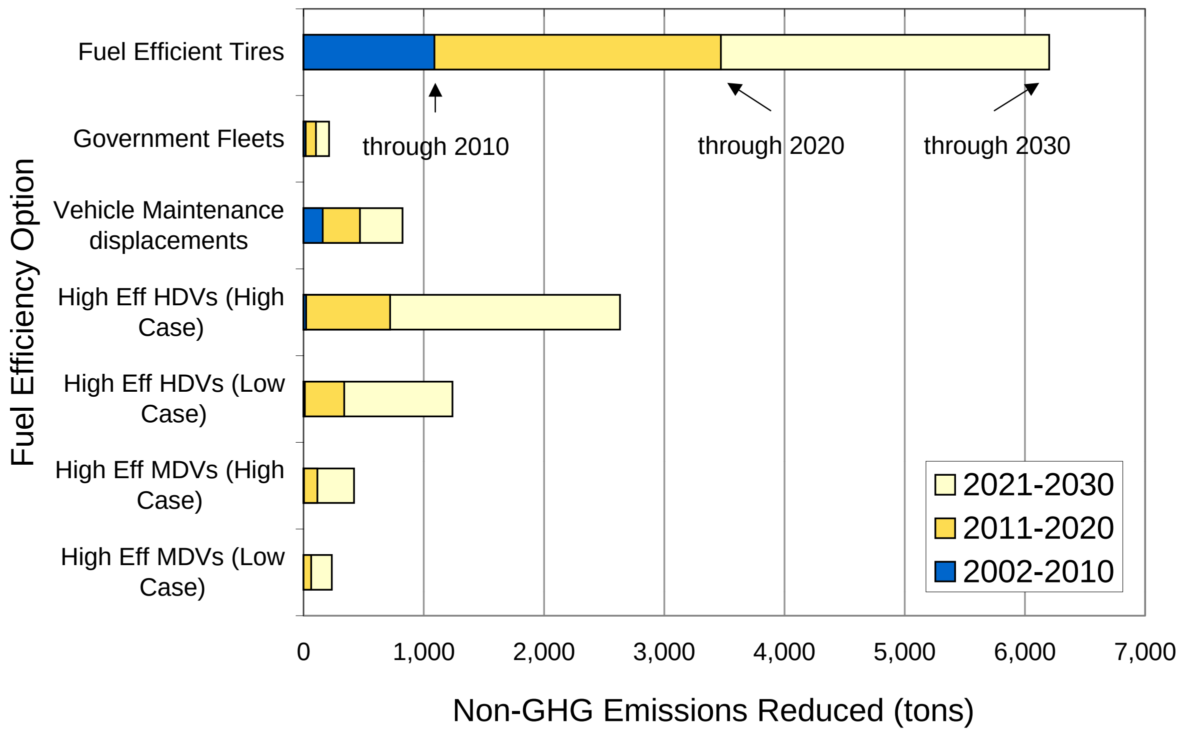


**Figure D-8. Group 1B-E Cumulative Criteria Pollutant Emission Reduction for 2002-2030**

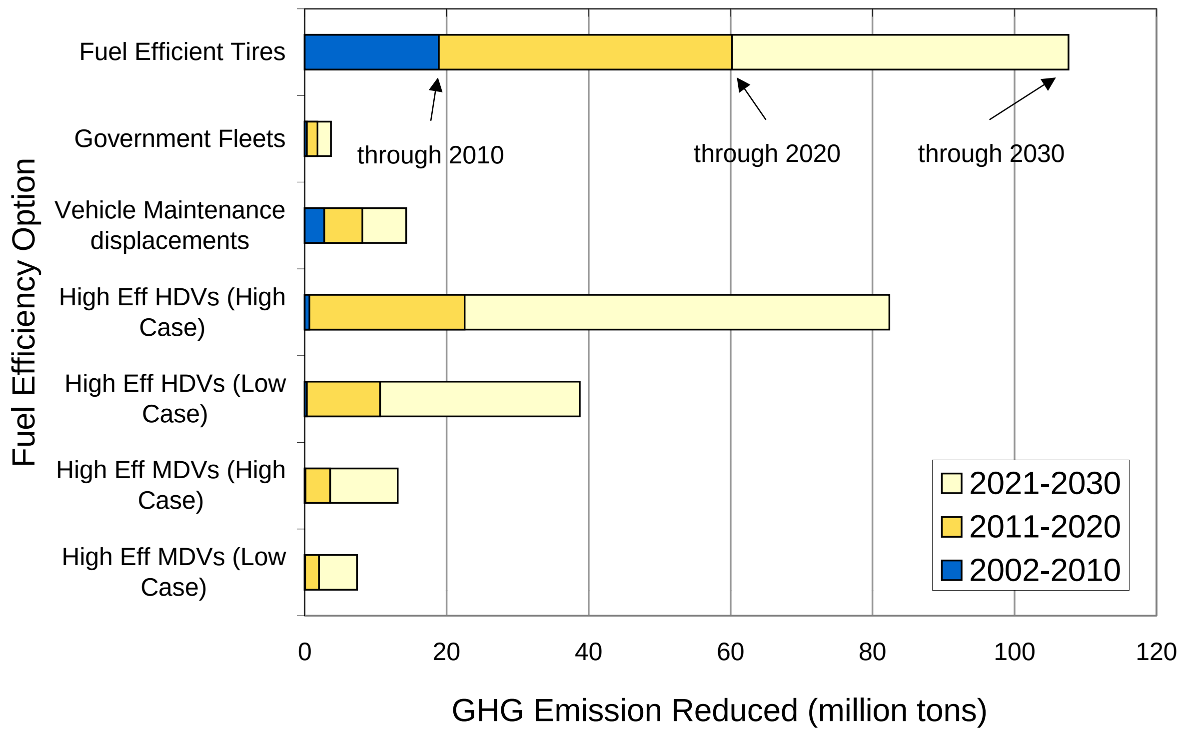


**Figure D-9. Group 1B-E Cumulative GHG Emission Reduction for 2002-2030**

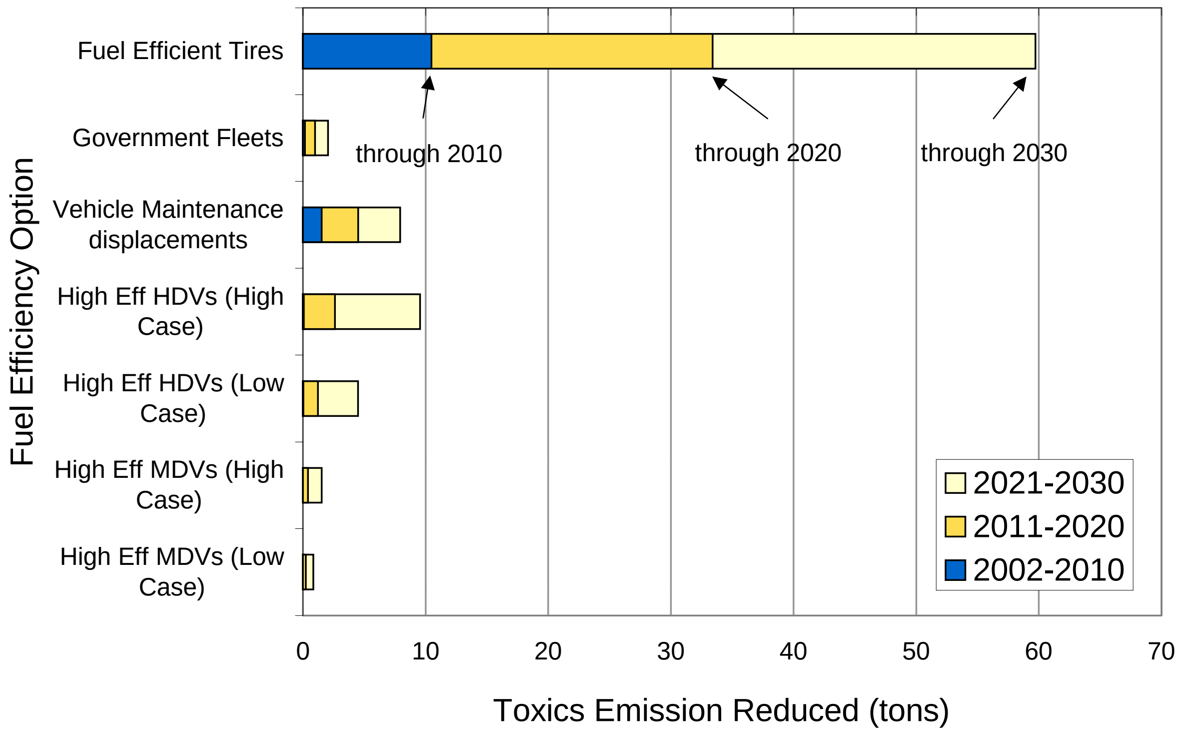


**Figure D-10. Group 1B-E Cumulative Toxics Emission Reduction for 2002-2030**

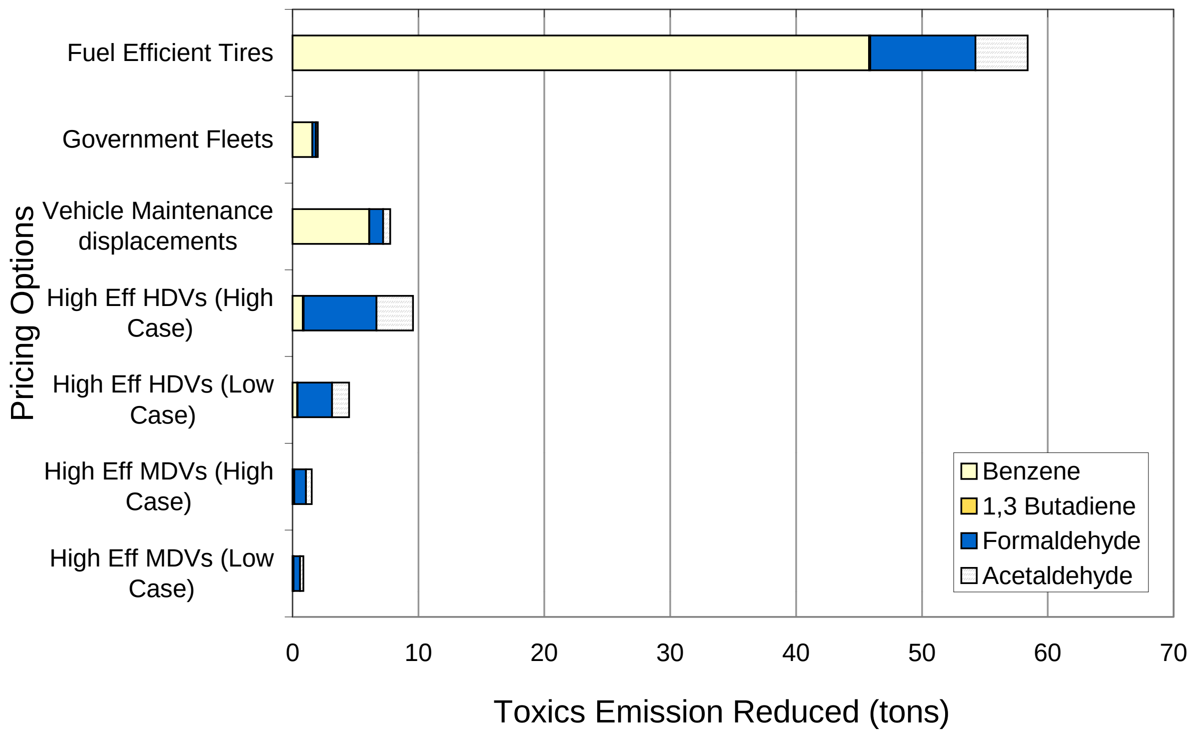


**Figure D-11. Group 1B-E Speciated Toxics Emissions Reduction from 2002-2030**

Figures D-12 through D-21 show the corresponding results for the Fuel Displacement Options (Group 2). These figures present the partial market penetration options separately from the full market penetration options.

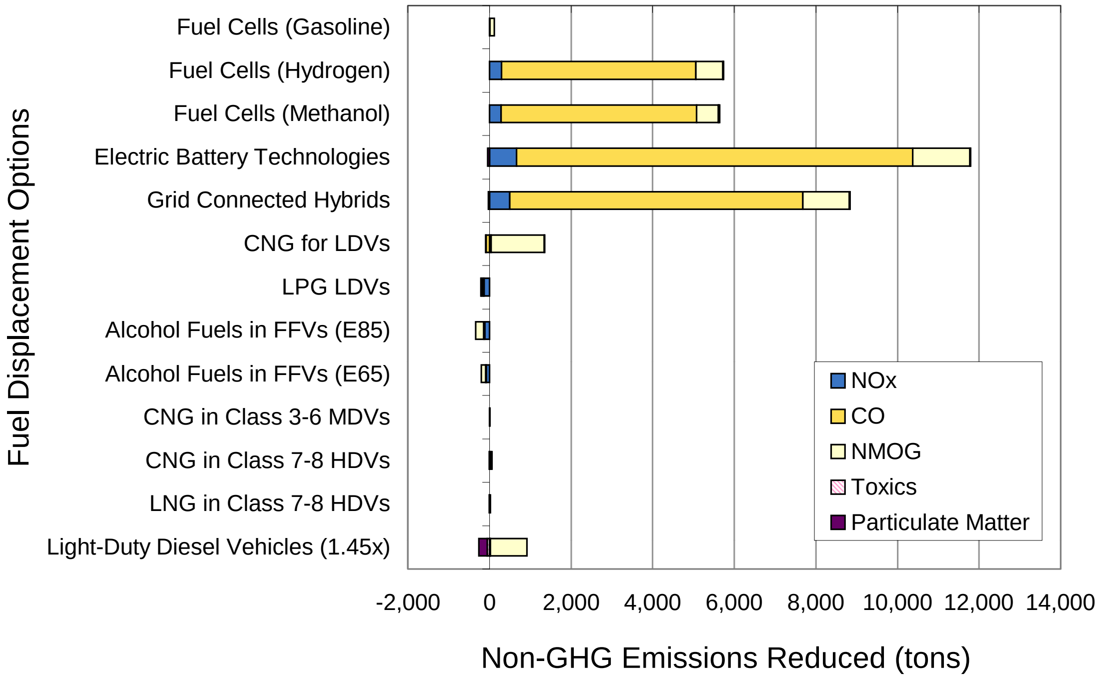


**Figure D-12. Group 2 Criteria Pollutant Emission Reduction in 2020**

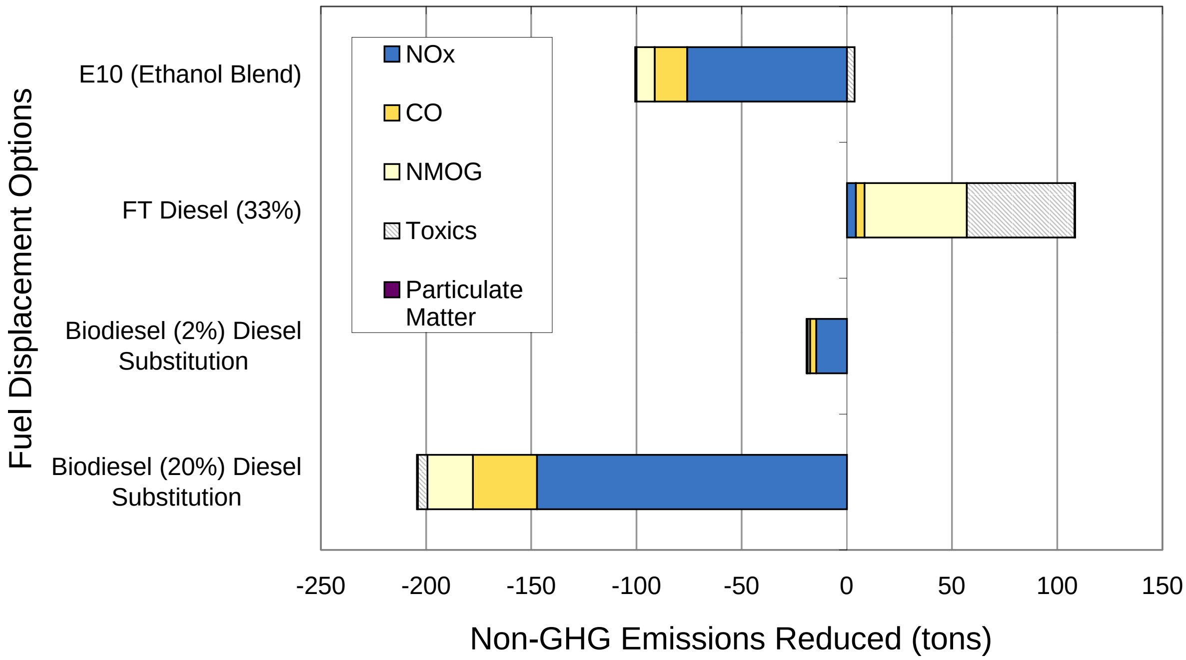


**Figure D-13. Group 2 Criteria Pollutant Emission Reduction in 2020 (Full Penetration Options)**

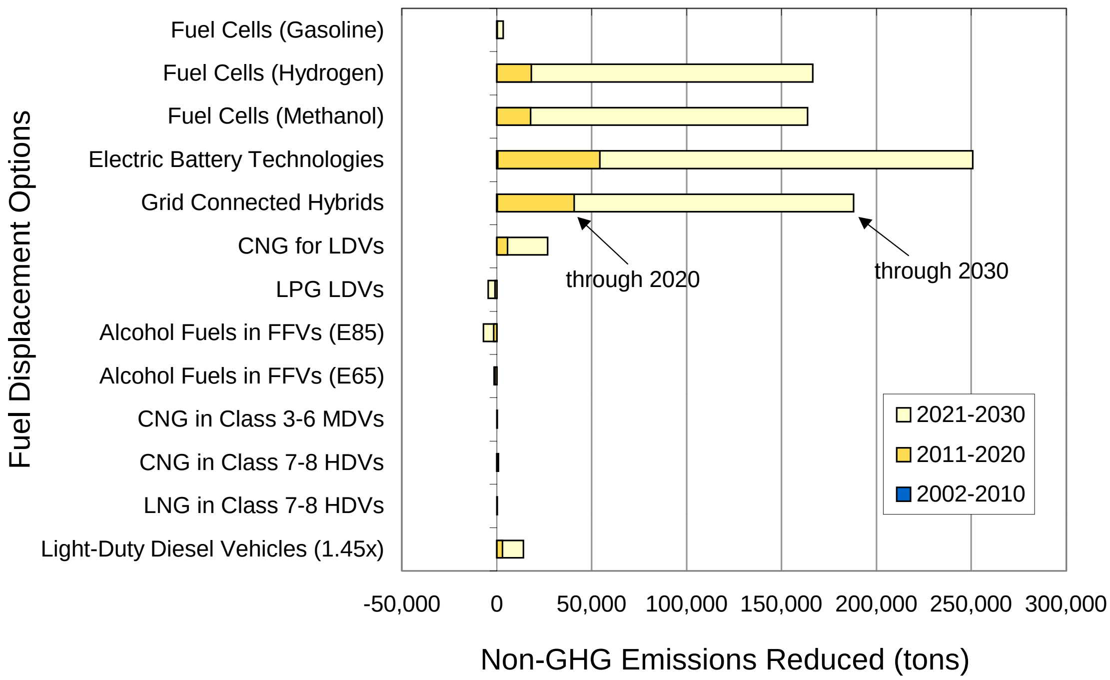


**Figure D-14. Group 2 Cumulative Criteria Pollutant Emission Reduction for 2002-2030**

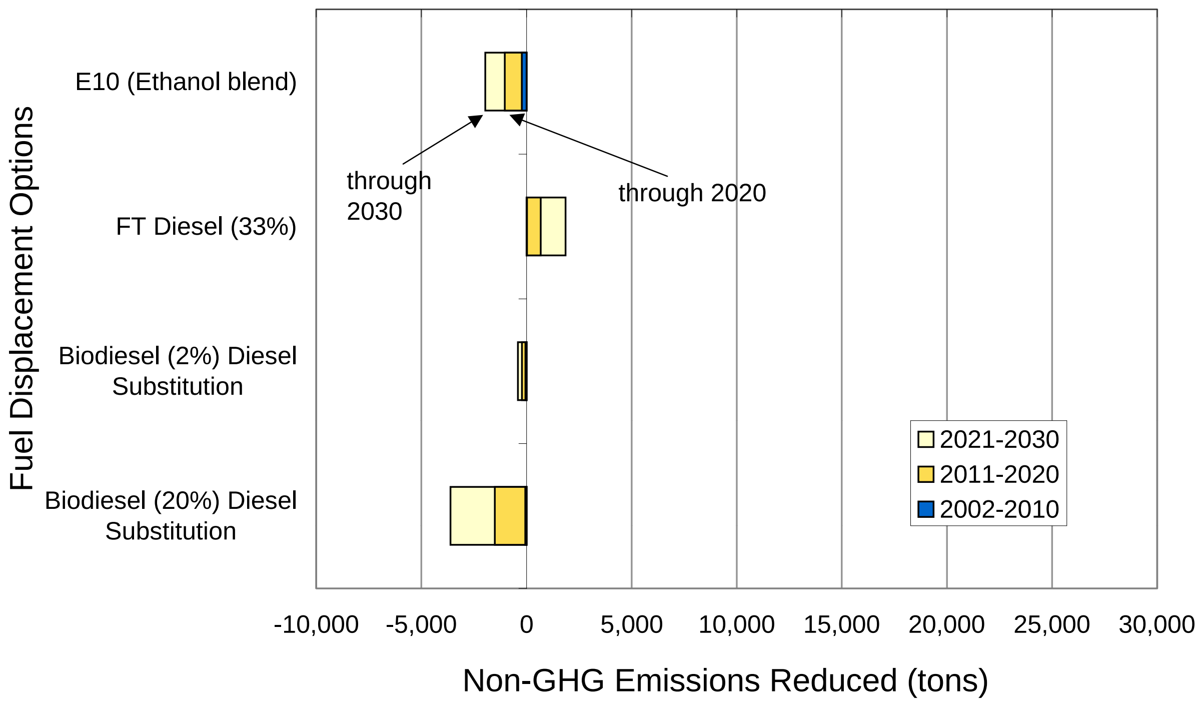


**Figure D-15. Group 2 Cumulative Criteria Pollutant Emission Reduction for 2002-2030 (Full Penetration Options)**

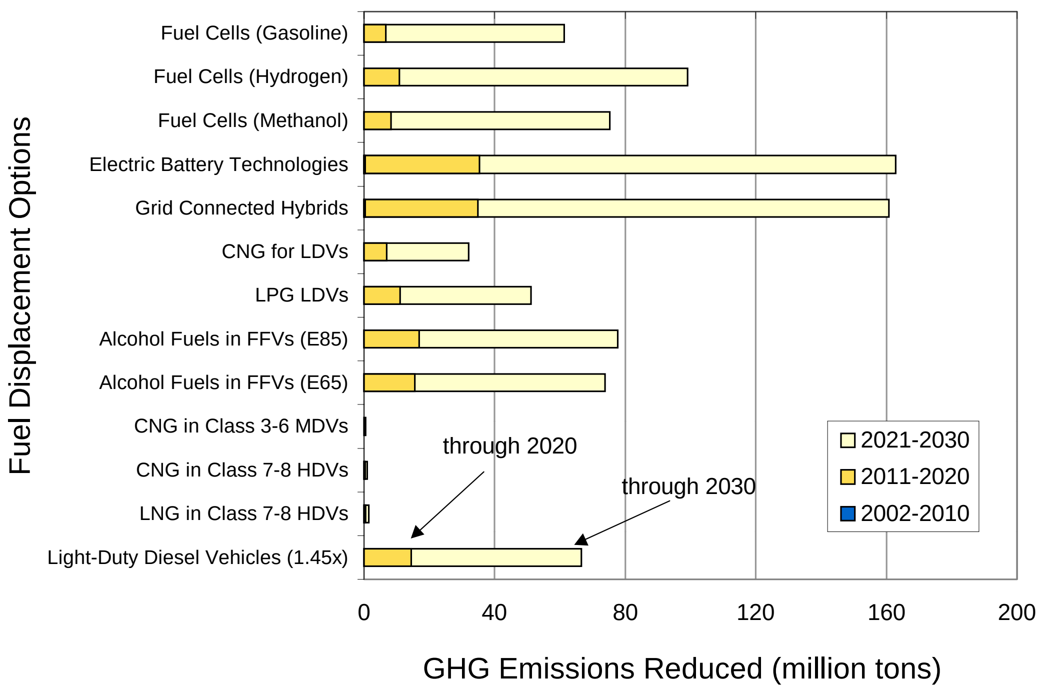


**Figure D-16. Group 2 Cumulative GHG Emission Reduction for 2002-2030**

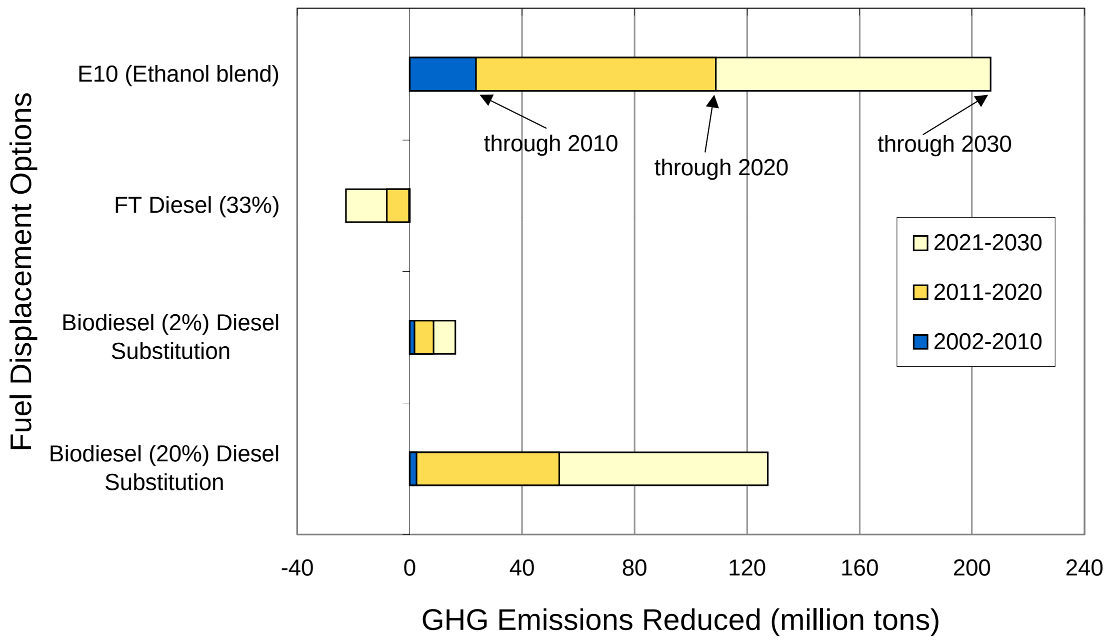


**Figure D-17. Group 2 Cumulative GHG Emission Reduction for 2002-2030 (Full Penetration Options)**

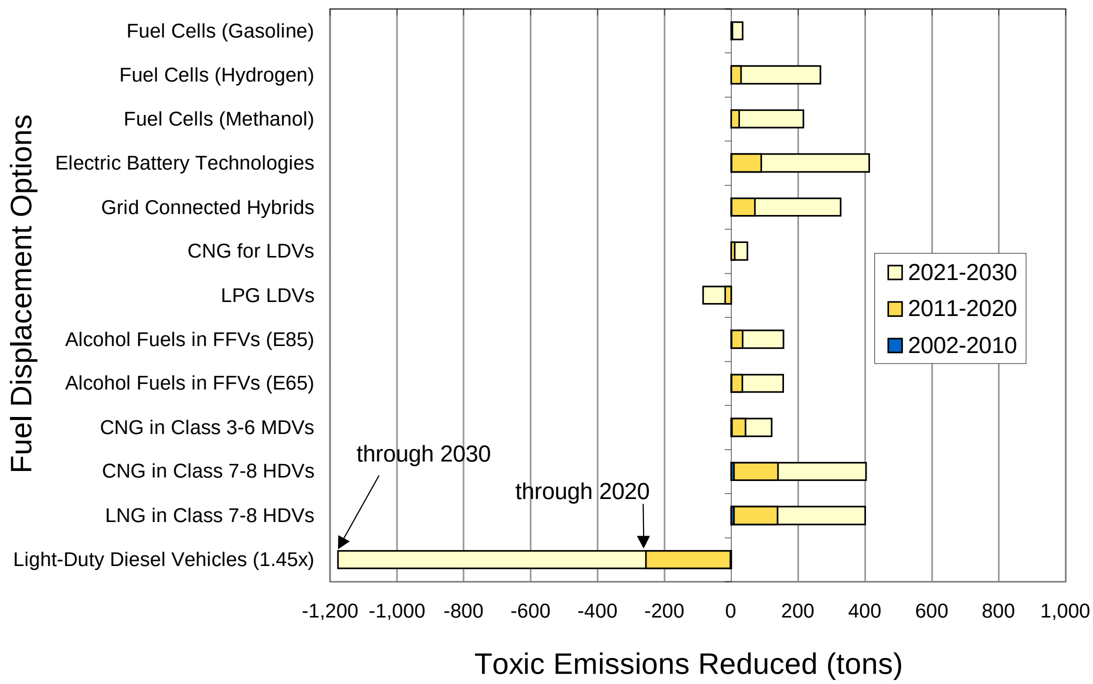


**Figure D-18. Group 2 Cumulative Toxics Emission Reduction for 2002-2030**

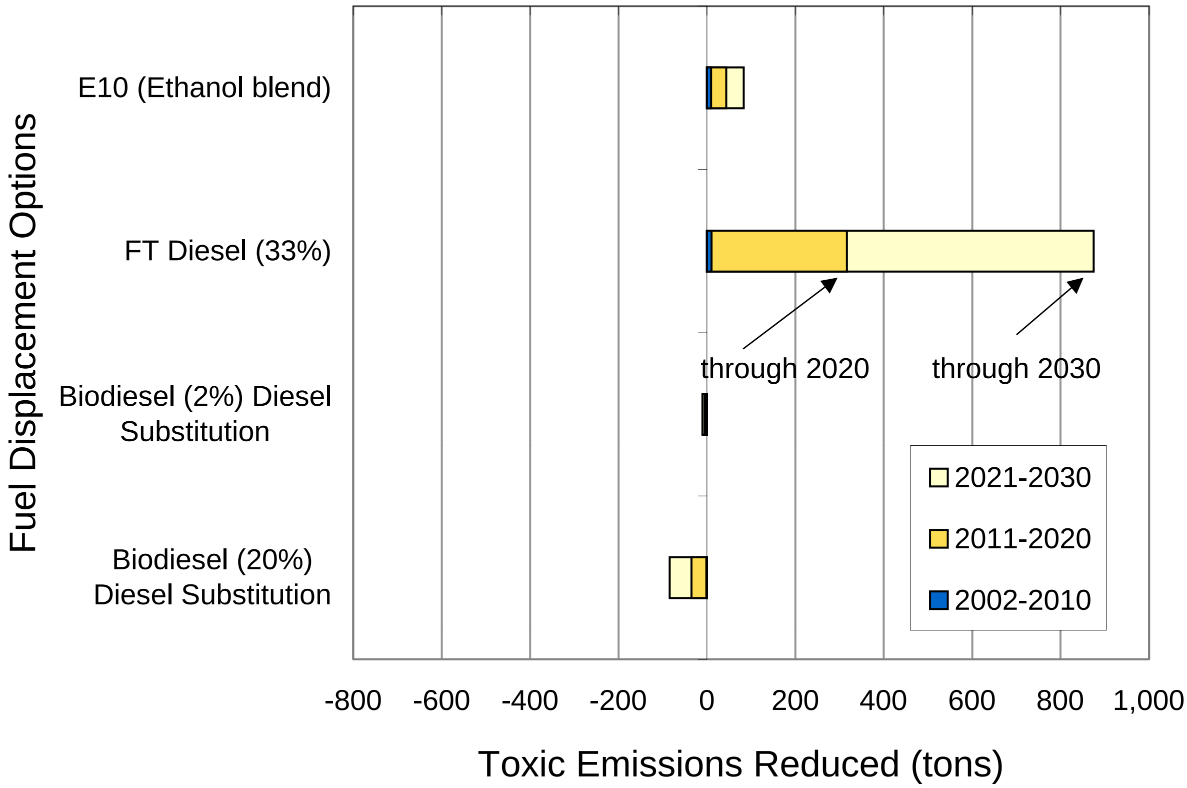


**Figure D-19. Group 2 Cumulative Toxic Emission Reduction for 2002-2030 (Full Penetration Options)**

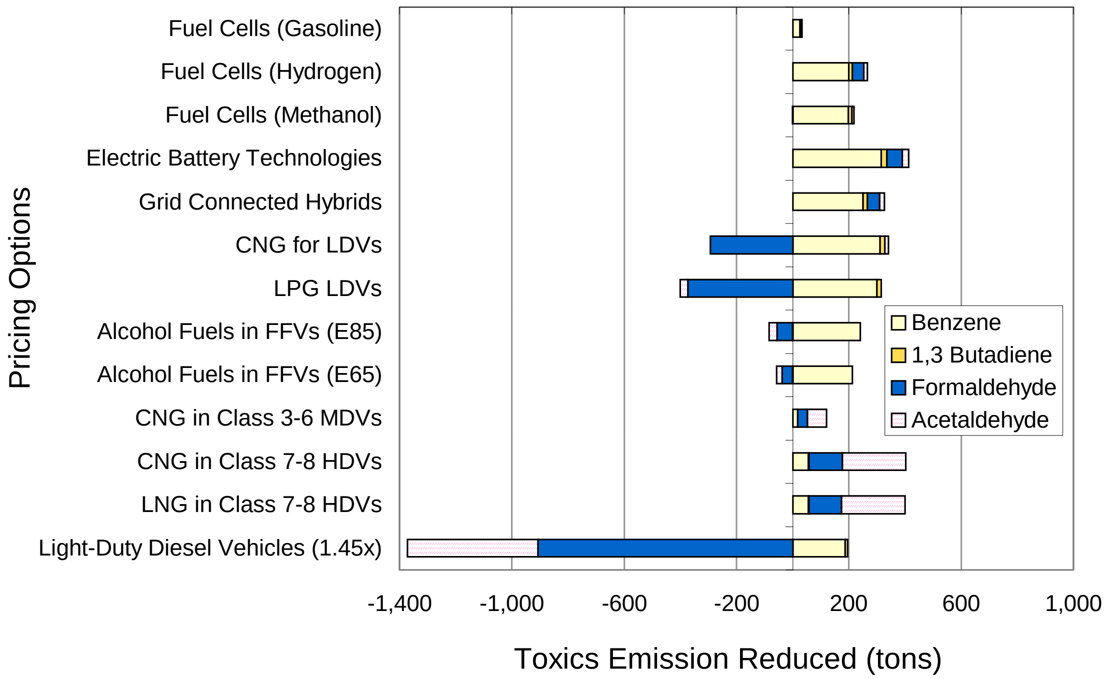


**Figure D-20. Group 2 Speciated Toxics Emissions Reduction from 2002-2030**

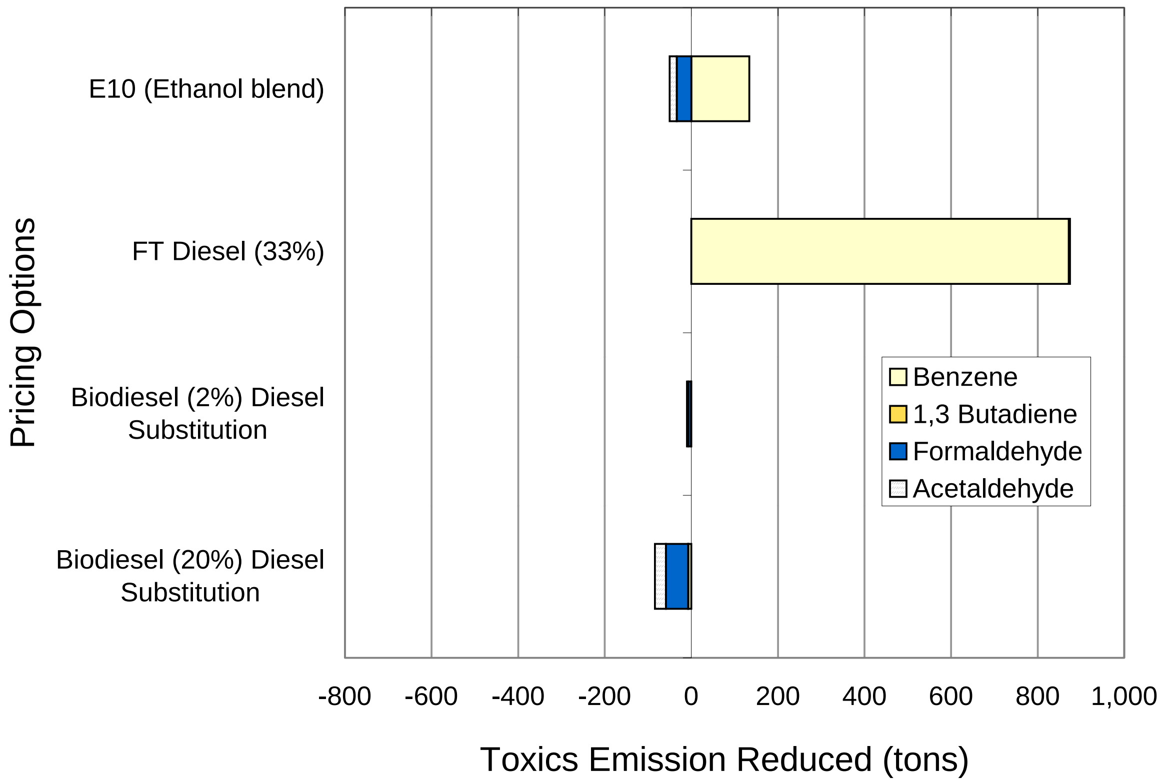


**Figure D-21. Group 2 Speciated Toxic, Emissions Reduction from 2002-2030**

The additional results for the Pricing (Group 3) options are presented in Figures D-22 through D-26.

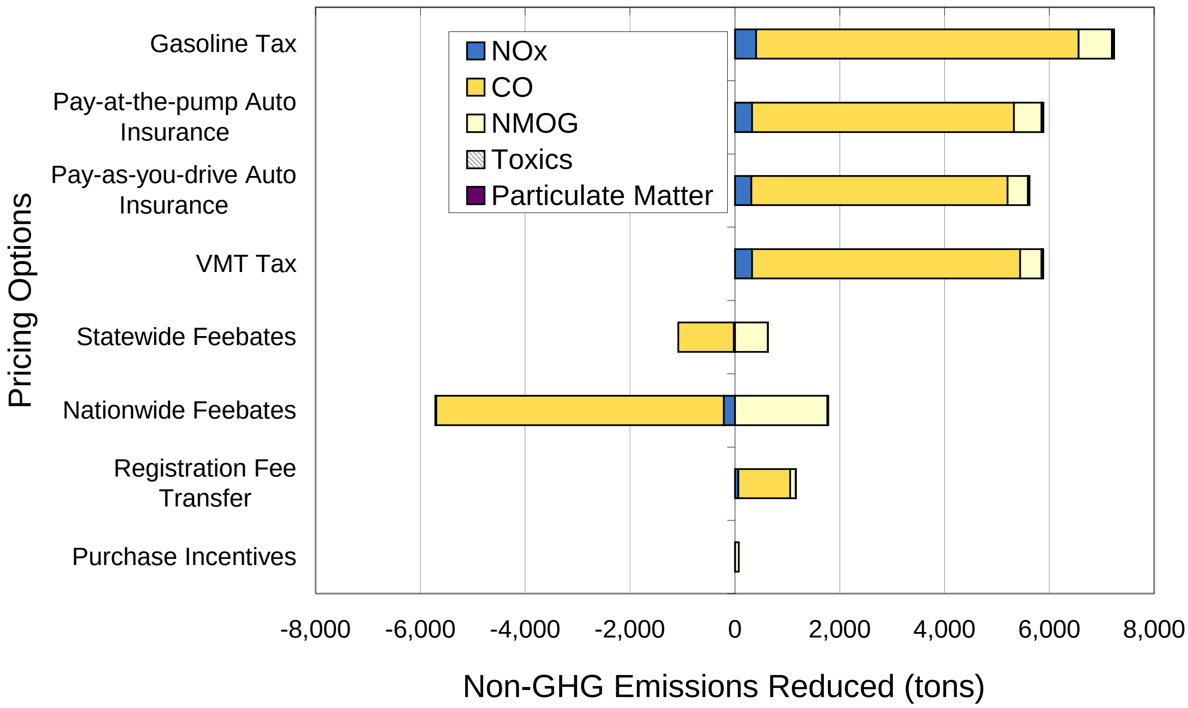


**Figure D-22. Group 3 Criteria Pollutant Emissions Reduction in 2020**

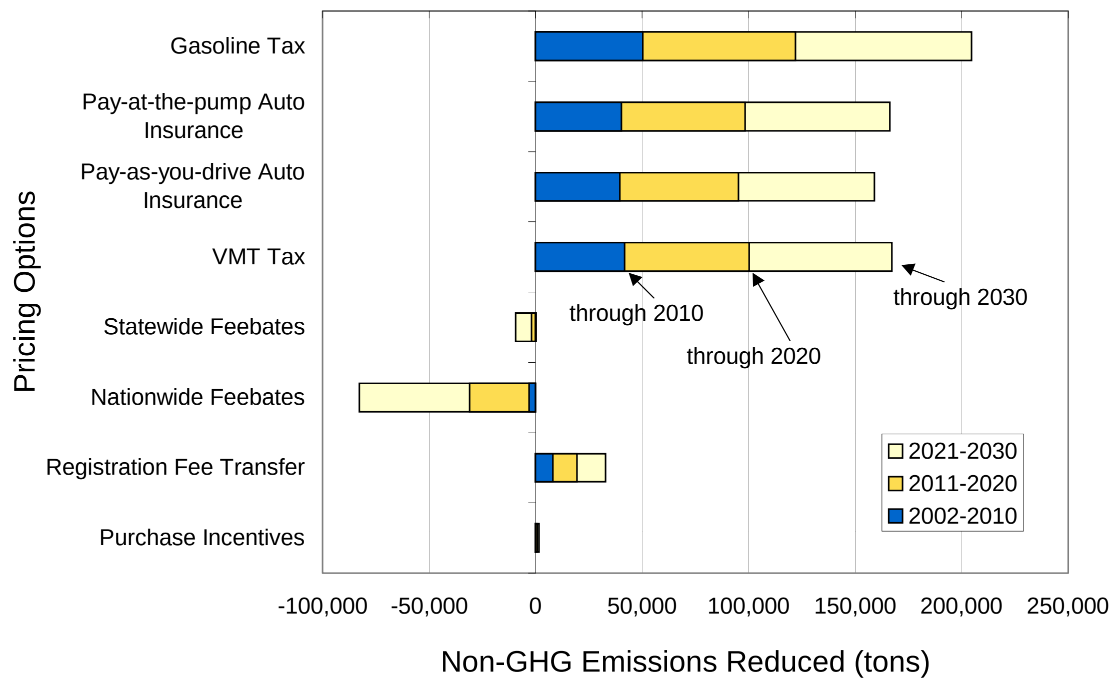


**Figure D-23. Group 3 Cumulative Criteria Pollutant Emissions Reduction for 2002-2030**

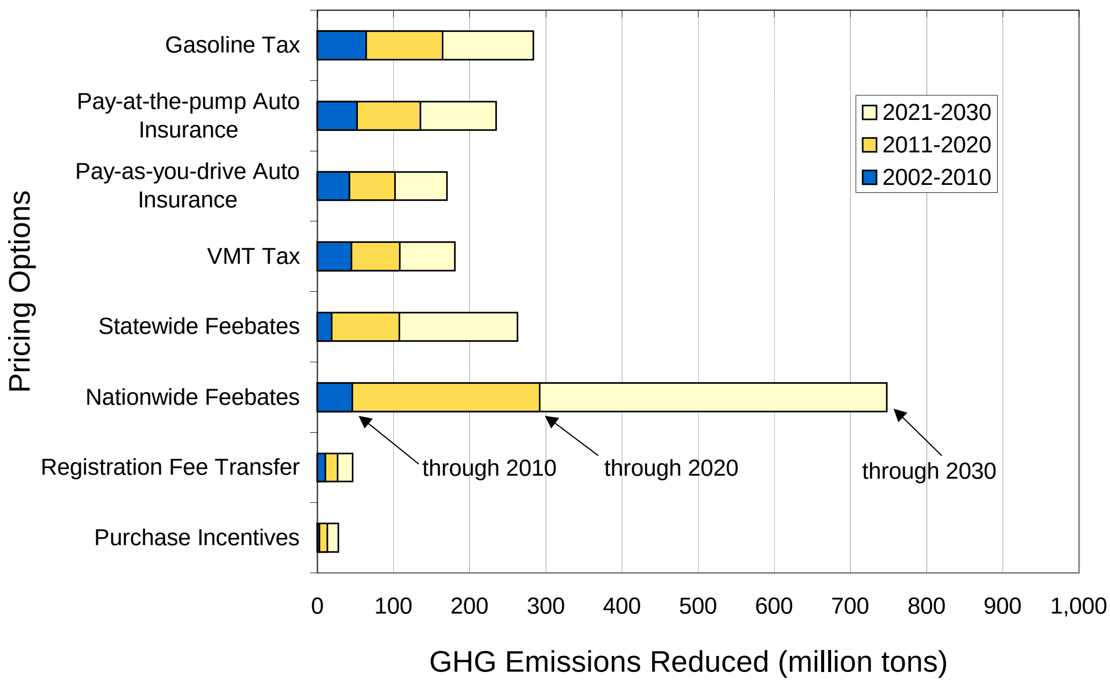


**Figure D-24. Group 3 Cumulative GHG Emissions Reduction for 2002-2030**

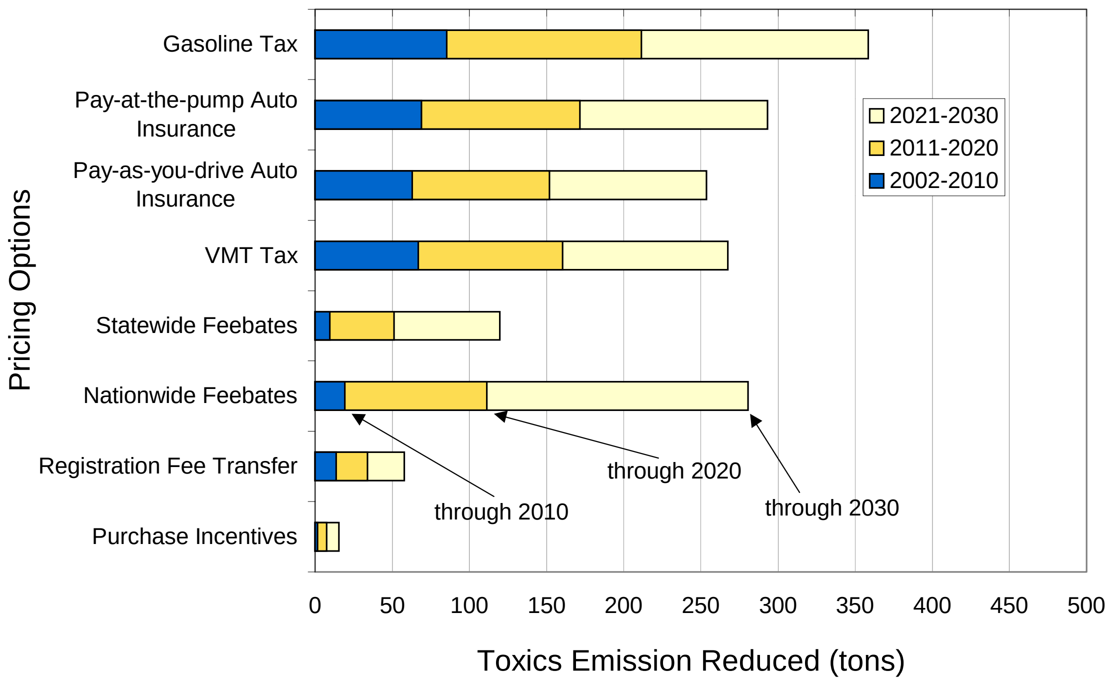


**Figure D-25. Group 3 Cumulative Toxics Emissions Reduction for 2002-2030**

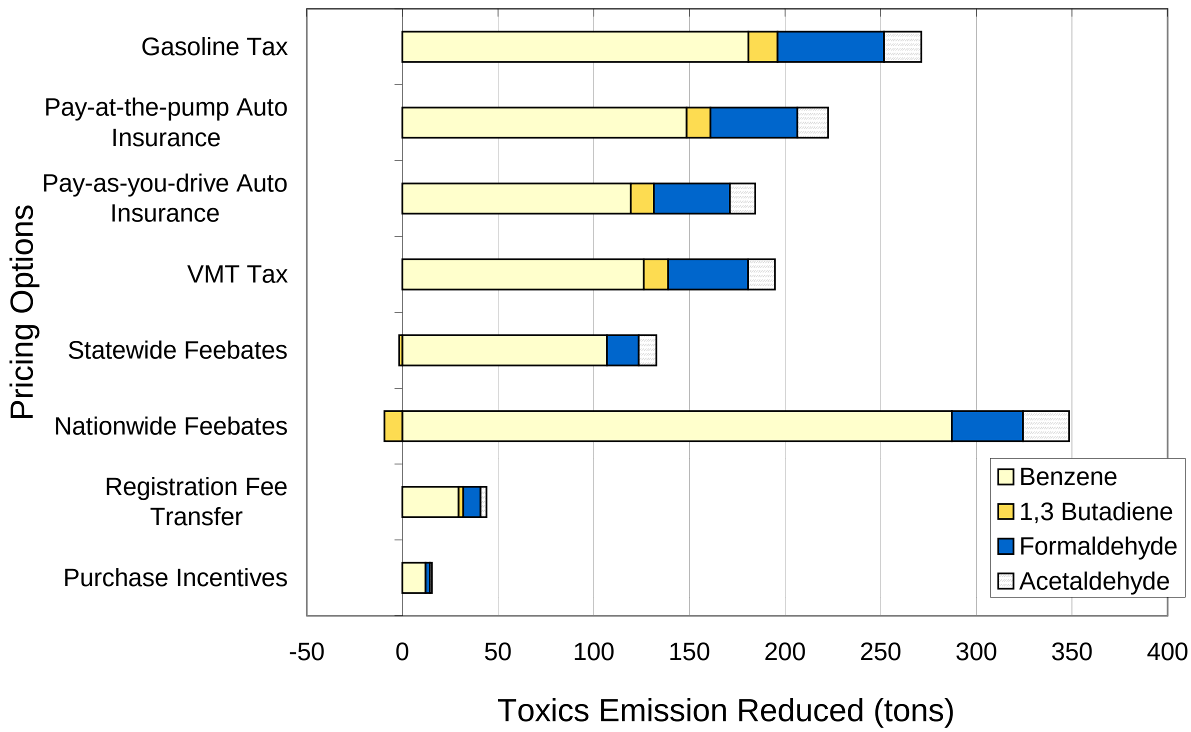


**Figure D-26. Group 3 Speciated Toxics Emissions Reduction from 2002-2030**

## Appendix E. PM Health Effects Concentration Response Functions and Corresponding Monetary Values

The purpose of this appendix is to provide more details on epidemiological studies selected in developing the concentration response (C-R) functions and present the monetary values used for estimating the benefits in the AB 2076 analysis.

As we mentioned in the Section 3, all C-R functions used in this analysis are drawn from U.S. Environmental Protection Agency's (U.S. EPA's) and California Air Resources Board's (ARB's) prior efforts on quantifying PM health effects. U.S. EPA's efforts have undergone years of public review and comment as well as full peer review by the U.S. EPA's independent Science Advisory Board. ARB's PM standard review report has also reviewed by the public and the Air Quality Advisory Committee, an external scientific peer review committee comprised of world-class scientists in the PM field. We believe that the C-R functions and monetary values used in this analysis are based on the best available scientific and economic studies.

### E.1 Concentration-Response Functions

C-R functions are equations that relate the change in the number of adverse health effect incidences in a population to a change in pollutant concentration experienced by that population. Different epidemiological studies have been used to estimate the relationship between PM and a particular health endpoint at different locations. They may have different functional forms, PM concentrations, health endpoints, and relate to different populations. Some studies have assumed that the relationship between a health endpoint and PM is best described by a linear form, i.e., the relationship between a health endpoint (Y) and PM is estimated by a linear regression in which Y is the dependent variable and PM is one of several independent variables. Other studies have assumed that the relationship is best described by a log-linear form, i.e., the relationship between the natural logarithm of Y and PM is estimated by a linear regression. Most common functions used in this analysis are in log-linear form with a few exceptions using logistic regressions.

A log linear C-R function is:

$$\Delta y = y_0 \cdot (e^{\beta \Delta PM} - 1) \cdot pop$$

where:

$\Delta y$ = changes in the incidence of a health endpoint corresponding to a particular change in PM
$y_0$ = baseline incidence rate per person
$\beta$ = coefficient
$\Delta PM$ = change in PM concentration
pop = population of a particular group that a study considered.

The parameters in the functions differ depending on the study. Some studies considered only members of a particular subgroup of the population, e.g., individuals 65 and older, while other studies considered the entire population in the study location. When using a C-R function from an epidemiological study to estimate changes in the incidence of a health endpoint corresponding to a particular change in PM in a location, it is important to use the appropriate value of parameters for the C-R function. That is, the measure of PM, the type of population, and the characterization of the health endpoint should be the same as or as close as possible to those used in the study that estimated the C-R function.

### E.1.1 Mortality

Premature mortality may result from either short-term or long-term exposure to pollution concentrations. Short-term exposure may result in excess mortality on the same day or within a few days of increased exposure. Long-term exposure (over a year or more) may result in mortality in excess of what it would be if PM levels were generally lower. Long-term exposure may capture a facet of the association between PM and mortality that is not captured by short-term exposure. In this analysis we did not assess the short-term exposure mortality because a sum of estimated effects from both study types would likely result in some degree of double counting of the effects.

#### E.1.1.1 Long-term Mortality (Krewski et al., 2000) Based on ACS Cohort

This study is a re-analysis of the Pope et al. (1995) study of $PM_{2.5}$ associated mortality, using American Cancer Society (ACS) data. It essentially confirms the original findings. An advantage of Krewski et al. over Pope et al. is that the reanalysis uses the annual mean $PM_{2.5}$ concentration rather than the annual median. Because the mean is affected more by high PM values than by the median, if high PM days are important in causing premature mortality, the annual mean may be preferable to the median as a measure of long-term exposure.

The C-R function to estimate the change in long-term mortality is:

$$\Delta \text{ Mortality} = - y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

$y_0$ = county-level all-cause annual death rate per person ages 30 and older
$\beta$ = 0.0046257
$\Delta PM$ = change in annual mean $PM_{2.5}$ concentration
pop = population of ages 30 and older
$\sigma_\beta$ = 0.0012046

Incidence Rate. To estimate county-specific baseline mortality incidence among individuals ages 30 and over, we used data from 1999 annual all cause deaths by age by county (Center for Health Statistics, California Department of Health, 1999).

Coefficient Estimate ($\beta$). The coefficient ($\beta$) is estimated from the relative risk (1.12) associated with a mean change of 24.5 $\mu g/m^3$ (Krewski et al., 2000, Part II - Table 31).

Standard Error ($\sigma_\beta$). The standard error for the $PM_{2.5}$ coefficient ($\beta$) is calculated as the average of the standard errors implied by the reported lower and upper bounds of the relative risk (Krewski et al., 2000, Part II – Table 31).

### E.1.2 Chronic Bronchitis (Abbey et al., 1995 and 1993, California)

Abbey et al. (1995) examined the relationship between estimated $PM_{2.5}$ (annual mean from 1966 to 1977), $PM_{10}$ (annual mean from 1973 to 1977), and total suspended particulate (TSP, annual mean from 1973 to 1977) and the same chronic respiratory symptoms in a sample population of 1,868 Californians. The initial survey was conducted in 1977 and the final survey in 1987. To ensure a better estimate of exposure, the study participants had to have been living in the same area for an extended period of time. In single-pollutant models, there was a statistically significant $PM_{2.5}$ relationship with development of chronic bronchitis, but not for airway obstructive disease (AOD) or asthma; $PM_{10}$ was significantly associated with chronic bronchitis and AOD; and TSP was significantly associated with all cases of all three chronic symptoms.

The C-R function to estimate the change in chronic bronchitis is:

$$\Delta \text{ Chronic Bronchitis} = - y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

| | | |
|---|---|---|
| $y_0$ | = | annual bronchitis incidence rate per person = 0.00378 (Abbey et al., 1993, Table 3) |
| $\beta$ | = | estimated $PM_{2.5}$ coefficient = 0.0132, $PM_{10}$ coefficient = 0.00932 |
| $\Delta PM$ | = | change in annual average PM concentration |
| Pop | = | population of ages 27 and older without chronic bronchitis = 0.9465*population 27+ |
| $\sigma_\beta$ | = | standard error of $\beta$ = 0.00680 for $PM_{2.5}$, 0.00475 for $PM_{10}$ |

Incidence Rate. The estimation of the incidence rate is detailed in “Final Heavy Duty Engine/Diesel Fuel Rule: Air Quality Estimation, Selected Health and Welfare Benefits Methods, and Benefit Analysis Results, Appendix C”, U.S. EPA, December 2000.

Coefficient Estimate ($\beta$). The estimated coefficient ($\beta$) for $PM_{2.5}$ is based on the relative risk (= 1.81) associated with 45 $\mu g/m^3$ change in $PM_{2.5}$ (Abbey et al., 1995, Table 2). The estimated coefficient ($\beta$) for $PM_{10}$ is based on the relative risk (= 1.36) associated with 60 $\mu g/m^3$ change in TSP (Abbey et al., 1993, Table 5). Assuming that $PM_{10}$ is 55% of TSP and that particulate greater than 10 micrometers are harmless.

Standard Error ($\sigma_\beta$). The standard error for the $PM_{2.5}$ coefficient ($\beta$) is calculated from the reported lower and upper bounds of the relative risk (0.98 to 3.25) (Abbey et al., 1995, Table 2).

### E.1.3 Hospital Admissions

Studies of a possible PM-hospitalization relationship have been conducted for a number of locations in the United States, including California. These studies use a daily time-series design and focus on hospitalizations with a first-listed discharge diagnosis attributed to diseases of the circulatory system (ICD9-CM codes 390-459) or diseases associated with the respiratory system (ICD9-CM codes 460-519). Subcategories within these groups are also often examined, with variation between studies in how the categories are defined. Common subcategories within circulatory are cardiovascular, which includes heart attack, and cerebrovascular, which includes stroke. Common subcategories within respiratory are chronic obstructive pulmonary disease (COPD), asthma, and pneumonia. Various age grouping are also considered, which vary across studies.

Some studies have examined the relationship between air pollution and emergency room (ER) visits. Because most emergency room visits do not result in an admission to the hospital we treated hospital admissions and ER visits separately, taking account of the fraction of ER patients that were admitted to the hospital.

#### E.1.3.1 Hospital Admissions for COPD (Samet et al., 2000a, 14 Cities)

Samet, et al. (2000a) examined the relationship between air pollution and hospital admissions for individuals age 65 and over in 14 cities across the country. Cities were selected on the basis of available air pollution data for at least four years between 1985 and 1994 during which at least 50% of days had observations between the city-specific start and end of measurements.

The C-R function to estimate the change in hospital admissions for COPD associated with daily changes in $PM_{10}$ is:

$$\Delta \text{ COPD Admissions} = - y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

$y_0$ = daily hospital admission rate for COPD per person 65 and older = $2.59 \times 10^{-5}$
$\beta$ = $PM_{10}$ coefficient = 0.00288
$\Delta PM$ = change in daily average PM concentration
pop = population age 65 and older
$\sigma_\beta$ = standard error of $\beta$ = 0.00139

Incidence Rate. COPD hospital admissions (ICD-9 codes: 490-492, 494-496) are based on "Patient Discharge Data 1998-1999," California Office of Statewide Health Planning and Development, 2000. Population data are from "Race/Ethnic Population with Age and Sex Detail, 1970-2040", California Department of Finance.

Coefficient Estimate ($\beta$). The coefficient is estimated from relative risk of 1.029 which is based on a 2.88 percent increase in admissions due to a $PM_{10}$ change of 10.0 $\mu g/m^3$ (Samet et al., 2000a, Part II - Table 14).

Standard Error ($\sigma_\beta$) The standard error was calculated as the average of the standard errors implied by the reported lower and upper bounds of the percent increase (Samet et al., 2000a, Part II - Table 14)

### E.1.3.2 Hospital Admissions for Pneumonia (Samet et al., 2000a, 14 Cities)

The C-R function to estimate the change in hospital admissions for pneumonia associated with daily changes in PM is:

$$\Delta \text{ Pneumonia Admissions} = -\, y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

$y_0$ = daily hospital admission rate for pneumonia per person 65 and older = $5.16 \times 10^{-5}$
$\beta$ = $PM_{10}$ coefficient = 0.00207
$\Delta PM$ = change in daily average PM concentration
pop = population age 65 and older
$\sigma_\beta$ = standard error of $\beta$ = 0.00058

Incidence Rate. Pneumonia hospital admissions (ICD-9 codes: 480-487) are based on "Patient Discharge Data 1998-1999," California Office of Statewide Health Planning and Development, 2000. Population data are from "Race/Ethnic Population with Age and Sex Detail, 1970-2040", California Department of Finance.

Coefficient Estimate ($\beta$). The coefficient is estimated from relative risk of 1.021 which is based on a 2.07 percent increase in admissions due to a $PM_{10}$ change of 10.0 $\mu g/m^3$ (Samet, et al., 2000a, Part II - Table 14).

Standard Error ($\sigma_\beta$). The standard error was calculated as the average of the standard errors implied by the reported lower and upper bounds of the percent increase (Samet, et al., 2000a, Part II - Table 14)

### E.1.3.3 Hospital Admissions for Cardiovascular Disease (Samet et al., 2000a, 14 Cities)

The C-R function to estimate the change in hospital admissions for cardiovascular disease associated with daily changes in $PM_{10}$ is:

$$\Delta \text{ CVD Admissions} = -\, y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

$y_0$ = daily hospital admission rate for cardiovascular disease per person 65 and older = $1.58 \times 10^{-4}$
$\beta$ = $PM_{10}$ coefficient = 0.00119
$\Delta PM$ = change in daily average PM concentration
pop = population age 65 and older
$\sigma_\beta$ = standard error of $\beta$ = 0.00011

Incidence Rate. Congestive heart failure hospital admissions (ICD-9 codes: 390-429) are based on "Patient Discharge Data 1998-1999," California Office of Statewide Health Planning and

Development, 2000. Population data are from “Race/Ethnic Population with Age and Sex Detail, 1970-2040”, California Department of Finance.

Coefficient Estimate (β). The coefficient is estimated from a relative risk of 1.012, which is based on a 1.19 percent increase in admissions due to a $PM_{10}$ change of 10.0 $\mu g/m^3$ (Samet et al., 2000a, Part II - Table 14).

Standard Error ($\sigma_\beta$). The standard error was calculated as the average of the standard errors implied by the reported lower and upper bounds of the percent increase (Samet et al., 2000a, Part II - Table 14)

#### E.1.3.4 Hospital Admissions for Asthma (Sheppard et al., 1999, Seattle)

Sheppard et al. (1999) studied the relation between air pollution in Seattle and non-elderly hospital admissions for asthma from 1987 to 1994. They used air quality data for $PM_{10}$, $PM_{2.5}$, coarse $PM_{2.5\text{-}10}$, $SO_2$, ozone, and CO in a Poisson regression model with controls for time trends, seasonal variations, and temperature-related weather effects. They found asthma hospital admissions associated with $PM_{10}$, $PM_{2.5}$, coarse $PM_{2.5\text{-}10}$, CO, and ozone. The C-R function is based on a two-pollutant model with CO and $PM_{2.5}$ and $PM_{10}$ single-pollutant model:

$$\Delta \text{ Asthma Admissions} = - y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

$y_0$ = daily hospital admission rate for asthma per person = $2.63 \times 10^{-6}$
$\beta$ = $PM_{2.5}$ coefficient = 0.002505, $PM_{10}$ coefficient = 0.002568
$\Delta PM$ = change in daily average PM concentration
pop = population of ages less than 65
$\sigma_\beta$ = standard error of $PM_{2.5}$ $\beta$ = 0.001045, standard error of $PM_{10}$ $\beta$ = 0.0007674

Incidence Rate. Hospital admissions for asthma (ICD-9 code: 493) are based on “Patient Discharge Data 1998-1999,” California Office of Statewide Health Planning and Development, 2000. Population data are from “Race/Ethnic Population with Age and Sex Detail, 1970-2040”, California Department of Finance.

Coefficient Estimate (β). Based on a model with CO, the daily average coefficient is estimated from the relative risk (1.03) associated with a change in $PM_{2.5}$ exposure of 11.8$\mu g/m^3$ (Sheppard et al., 1999, Table 3 and p. 28).

Standard Error ($\sigma_\beta$). The standard error was calculated as the average of the standard errors implied by the reported lower and upper bounds of the relative risk (Sheppard et al., 1999, p. 28).

#### E.1.3.5 Emergency Room Visits for Asthma (Schwartz et al., 1993, Seattle)

Schwartz et al. (1993) examined the relationship between air quality and emergency room visits for asthma in persons under 65, and 65 and over who lived in Seattle from September 1989 to

September 1990. Using single-pollutant models they found daily levels of $PM_{10}$ linked to ER visits in individuals younger than 65.

The C-R function to estimate the change in daily emergency room visits for asthma associated with daily changes in $PM_{10}$ is:

$$\Delta \text{ Asthma ER Visits} = - y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

| | | |
|---|---|---|
| $y_0$ | = | daily ER visits for asthma per person under 65 years old = $4.48 \times 10^{-6}$ |
| $\beta$ | = | $PM_{10}$ coefficient (Schwartz et al., 1993, p. 829) = 0.00367 |
| $\Delta PM$ | = | change in daily average PM concentration |
| pop | = | population of ages 0-64 |
| $\sigma_\beta$ | = | standard error of $\beta$ (Schwartz et al., 1993, p. 829) = 0.00126 |

Incidence Rate. Smith, et al. (1997, p. 789) reported that in 1987 there were 445,000 asthma admissions and 1.2 million asthma ER visits. Assuming that all asthma hospital admissions pass through the ER room, then 37% of ER visits end up as hospital admissions. By subtracting out those visits that end up as admissions, ER visits = 1.7*asthma admission rate = 1.7*2.63 E-6 =4.48 E-6. Asthma hospital admissions (ICD-9 code: 493) rate are based on "Patient Discharge Data 1998-1999," California Office of Statewide Health Planning and Development, 2000, and population data are from "Race/Ethnic Population with Age and Sex Detail, 1970-2040", California Department of Finance.

### E.1.4 Minor Illness

In addition to chronic illnesses and hospital admissions, there is considerable scientific research that has reported significant relationships between elevated air pollution levels and other morbidity effects. Controlled human studies have established relationships between air pollution and symptoms such as cough, pain on deep inspiration, wheeze, eye irritation and headache. In addition, epidemiological research has found relationships between air pollution exposure and acute infectious diseases (e.g., bronchitis, sinusitis) and a variety of "symptom-day" categories. Some "symptom-day" studies examine excess incidences of days with identified symptoms such as wheeze, cough, or other specific upper or lower respiratory symptoms. Other studies estimate relationships for days with a more general description of days with adverse health impacts, such as "respiratory restricted activity days" or work loss days.

#### E.1.4.1 Upper Respiratory Symptoms (Pope et al., 1991)

Using logistic regression, Pope et al. (1991) estimated the impact of $PM_{10}$ on the incidence of a variety of minor symptoms in 55 subjects (34 "school-based" and 21 "patient-based") living in the Utah Valley from December 1989 through March 1990. The children in the Pope et al. study were asked to record respiratory symptoms in a daily diary. Pope et al. defined upper respiratory symptoms as consisting of one or more of the following symptoms: runny or stuffy nose; wet cough; and burning, aching, or red eyes. The sample in this study was relatively small and is most representative of the asthmatic population, rather than the general population. The school-based subjects (ages 9 to 11) were chosen based on "a positive response to one or more of three questions: ever wheezed without a cold, wheezed for 3 days or more out of the week for a month or longer, and/or had a doctor say the 'child has asthma' (Pope et al., 1991, p. 669)." The patient-based subjects (ages 8 to 72) were receiving treatment for asthma and were referred by local physicians. Regression results for the school-based sample (Pope et al., 1991, Table 5) showed $PM_{10}$ significantly associated with both upper and lower respiratory symptoms. The patient-based sample did not find a significant $PM_{10}$ effect. The results from the school-based sample are used here.

The C-R function used to estimate the change in upper respiratory symptoms is:

$$\Delta Upper\ Respiratory\ Symptoms = -\left[\frac{y_0}{(1-y_0)\cdot e^{\Delta PM\beta} + y_0} - y_0\right]\cdot pop$$

where:

- $y_0$ = daily upper respiratory symptom incidence rate per person = 0.3419
- $\beta$ = estimated $PM_{10}$ logistic regression coefficient = 0.0036 (Pope et al., 1991, Table 5)
- $\Delta PM$ = change in daily average PM concentration
- pop = asthmatic population ages 9 to 11 = 6.91% of population ages 9 to 11
- $\sigma_\beta$ = standard error of $\beta$ (Pope et al., 1991, Table 5) = 0.0015

Incidence Rate. The incidence rate is published in Pope et al. (Pope et al., 1991, Table 2). Taking a sample-size-weighted average, one gets an incidence rate of 0.3419.

#### E.1.4.2 Lower Respiratory Symptoms (Schwartz et al., 1994)

Schwartz et al. (1994) used logistic regression to link lower respiratory symptoms in children with $SO_2$, $NO_2$, ozone, $PM_{10}$, $PM_{2.5}$, sulfate and $H^+$ (hydrogen ion). Children were selected for the study if they were exposed to indoor sources of air pollution: gas stoves and parental smoking. The study enrolled 1,844 children in 1984 into a year-long study. The study was conducted in different years (1984 to 1988) in six cities. The students were in grades two through five at the time of enrollment in 1984. By the completion of the final study, the cohort would then be in the eighth grade (ages 13-14); this suggests an age range of 7 to 14.

In single pollutant models $SO_2$, $NO_2$, $PM_{2.5}$, and $PM_{10}$ were significantly linked to coughing. In two-pollutant models, $PM_{10}$ had the most consistent relationship with coughing. In models for upper respiratory symptoms, they reported a marginally significant association for $PM_{10}$. In models for lower respiratory symptoms, they reported significant single-pollutant models, using $SO_2$, $O_3$, $PM_{2.5}$, $PM_{10}$, $SO_4$, and $H^+$.

The C-R function used to estimate the change in lower respiratory symptoms is:

$$\Delta Lower\ Respiratory\ Symptoms = -\left[\frac{y_0}{(1-y_0)\cdot e^{\Delta PM\beta} + y_0} - y_0\right]\cdot pop$$

where:

$y_0$ = daily lower respiratory symptom incidence rate per person = 0.0012
$\beta$ = estimated $PM_{2.5}$ logistic regression coefficient = 0.01823
$\Delta PM$ = change in daily average PM concentration
pop = population of ages 7-14
$\sigma_\beta$ = standard error of $\beta$ = 0.00586

Incidence Rate. The proposed incidence rate, 0.12 percent, is based on the percentiles in Schwartz et al. (Schwartz et al., 1994, Table 2). The calculation is detailed in "Final Heavy Duty Engine/Diesel Fuel Rule: Air Quality Estimation, Selected Health and Welfare Benefits Methods, and Benefit Analysis Results, Appendix C", U.S. EPA, December 2000.

Coefficient Estimate ($\beta$). The coefficient is calculated from the reported odds ratio (= 1.44) in a single-pollutant model associated with a 20 $\mu g/m^3$ change in $PM_{2.5}$ (Schwartz et al., 1994, Table 5).

Standard Error ($\sigma_\beta$). The standard error for the coefficient is calculated from the reported lower and upper bounds of the odds ratio (Schwartz et al., 1994, Table 5).

#### E.1.4.3 Asthma Attacks, (Whittemore and Korn, 1980)

Whittemore and Korn (1980) examined the relationship between air pollution and asthma attacks in a survey of 443 children and adults, living in six communities in southern California during three 34-week periods in 1972-1975. The analysis focused on TSP and ozone. In a two-pollutants model, daily levels of both TSP and $O_3$ were significantly related to reported asthma attacks.

The C-R function to estimate the change in the number of asthma attacks is:

$$\Delta\ Asthma\ Attacks = -[\frac{y_0}{(1-y_0)\cdot e^{\Delta PM\beta} + y_0} - y_0]\cdot pop$$

where:

$y_0$ = daily incidence of asthma attacks = 0.027 (Krupnick, 1988, p. 4-6)
$\beta$ = $PM_{10}$ coefficient = 0.00144
$\Delta PM$ = change in daily PM concentration
pop = population of asthmatics of all ages = 5.61% of the population of all ages.
$\sigma_\beta$ = standard error of $\beta$ = 0.000556

Incidence Rate. The annual rate of 9.9 asthma attacks per asthmatic is divided by 365 to get a daily rate. A figure of 9.9 is roughly consistent with the recent statement that "People with asthma have more than [a combined] 100 million days of restricted activity" each year (National Heart, Lung, and Blood Institute 1997, p. 1). This 100 million incidence figure coupled with the 1996 population of 265,557,000 (U.S. Bureau of the Census, 1997, Table 2) and the latest asthmatic prevalence rate of 5.61% (Current Estimates From the National Health Interview

Survey, 1994, U.S. Department of Health and Human Services, 1995, Table 57), suggest an annual asthma attack rate per asthmatic of 6.7.

Coefficient Estimate ($\beta$). Based on a model with ozone, the coefficient is based on a TSP coefficient (0.00079) (Whittemore and Korn, 1980, Table 5). Assuming that $PM_{10}$ is 55 percent of TSP and that particulates greater than ten micrometers are harmless.

Standard Error ($\sigma_\beta$). The standard error is calculated from the two-tailed p-value (<0.01) reported by Whittemore and Korn (1980, Table 5), which implies a t-value of at least 2.576 (assuming a large number of degrees of freedom).

#### E.1.4.4 Work Loss Days (Ostro, 1987)

Ostro (1987) estimated the impact of $PM_{2.5}$ on the incidence of work-loss days (WLDs), restricted activity days (RADs), and respiratory-related RADs (RRADs) in a national sample of the adult working population, ages 18 to 65, living in metropolitan areas. The annual national survey results used in this analysis were conducted in 1976-1981. Ostro reported that two-week average $PM_{2.5}$ levels were significantly linked to work-loss days, RADs, and RRADs, however there was some year-to-year variability in the results. Separate coefficients were developed for each year in the analysis (1976-1981); these coefficients were pooled. The coefficient used in the concentration-response function used here is a weighted average of the coefficients in Ostro (1987, Table III) using the inverse of the variance as the weight.

The C-R function to estimate the change in the number of work-loss days is:

$$\Delta \text{ WLD} = - y_0 \cdot (e^{-\beta \Delta PM} - 1) \cdot pop$$

where:

$y_0$ = daily work-loss-day incidence rate per person = 0.00648
$\beta$ = inverse-variance weighted $PM_{2.5}$ coefficient = 0.0046
$\Delta PM$ = change in daily average PM concentration
pop = population of ages 18 to 65
$\sigma_\beta$ = standard error of $\beta$ = 0.00036

Incidence Rate. The estimated 1994 annual incidence rate is the annual number (376,844,000) of WLD per person in the age 18-64 population divided by the number of people in 18-64 population (159,361,000). The 1994 daily incidence rate is calculated as the annual rate divided by 365. Data are from U.S. Bureau of the Census (1997, Table 14) and current estimates from the national health interview survey (CDC/NCHS 1998, Table 41).

Coefficient Estimate ($\beta$). The coefficient used in the C-R function is a weighted average of the coefficients in Ostro (1987, Table III) using the inverse of the variance as the weight.

Standard Error ($\sigma_\beta$). The standard error of the coefficient calculation is detailed in “Final Heavy Duty Engine/Diesel Fuel Rule: Air Quality Estimation, Selected Health and Welfare Benefits Methods, and Benefit Analysis Results, Appendix C”, U.S. EPA, December 2000.

### E.2 Monetary Values of Reducing PM Health Effects

There are various methodologies in valuing reduction of adverse health benefits. The most commonly used are cost of illness (COI) and willingness to pay (WTP) methods. The COI approach generally includes direct medical expenses and lost earnings. It however does not account for pain and suffering due to sickness. The preferred approach economists have taken is WTP method. The WTP approach captures broader factors including pain and suffering that affect people's choice concerning an improvement in their health. Both the U.S. EPA's section 812 report to Congress (U.S. EPA, 1999) and the HDE rule analysis (U.S. EPA, 2000) provided very detailed discussions on valuation of each health endpoint and the uncertainties associated with the valuation estimates. The following table summarizes unit values of each health endpoint used in this analysis as well as the sources of these values. Most unit values are drawn from U.S. EPA's two reports except for hospital admissions which are based recent California hospitalization cost data.

**Unit Economic Value of Health Endpoints (1999$)**

| Health Endpoint | Mean Estimate | References |
|---|---|---|
| **Mortality** | | |
| Long-term Exposure Mortality | $6.12 million | U.S. EPA, 1999 |
| **Chronic Illness**: | | |
| Chronic Bronchitis | $331,000 per case | U.S. EPA, 2000 |
| **Hospital Admissions:** | | |
| Cardiovascular | $30,180 per case | California OSHPD |
| Pneumonia | $22,114 per case | California OSHPD |
| COPD | $18,612 per case | California OSHPD |
| Asthma | $10,955 per case | California OSHPD |
| Asthma-related ER visit | $298.62 per case | U.S. EPA, 2000 |
| **Minor Illnesses:** | | |
| Lower Respiratory Symptoms | $15.30 per symptom-day | U.S. EPA, 2000 |
| Upper Respiratory Symptoms | $24.22 per symptom-day | U.S. EPA, 2000 |
| Work loss days | $105.83 per day | U.S. EPA, 2000 |

1990 $ values used by U.S. EPA (1999) are adjusted to 1999$ by CPI-based inflation factors.

## E.3 References for Appendix E


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## Appendix F. Water and Soil Impacts

Each step in the production and marketing of petroleum-based fuels and products potentially impact the environment and public health. Marine environments and coastal beaches are impacted by marine tanker spills. Soil, surface and groundwater are affected by releases from pipelines. Discharge from refineries impacts the environment, and accidents at refineries are responsible for the deaths and injuries of workers. Transportation by tanker trucks places other drivers at risk, and in the event of a rollover and spill, can cause soil, surface water and groundwater contamination. Leaks from underground tanks at dispensing facilities can compromise the quality of drinking water supplies. Air pollution and impacted public health are the end result of exhaust from gasoline- and diesel-fueled engines. The combined effect on water, soil, and air are known as multimedia impacts. This section focuses on water and soil impacts.

Although consumers can readily see the price paid for petroleum fuels at the pump, some environmental impacts are not reflected in the price. Most components of spill cleanup are internalized costs; that is, the cost of cleanup is paid by the petroleum industry, and is consequently included in the petroleum pricing structure. These internalized costs are paid either in the form of out-of-pocket per incident, or are financed by a liability fund. Petroleum spill cleanup costs paid by the public sector, or damages to the environment that are not remediated, are externalized costs. There is limited information that quantifies these externalized costs, as much of the documented spill cleanup cost is internalized by the petroleum industry. Additionally, there are externalized costs, such as the damage to public health, and deaths of animals, plants, and even humans, that are difficult to quantify in monetary terms and are not typically passed on to the consumer on a per-gallon of fuel basis.

In this evaluation, data from various sources are compiled to allow an estimate of spill cleanup and property damage costs at several points along the petroleum distribution chain. These estimated spill cleanup costs are considered to be internalized to the petroleum pricing structure. This evaluation does not attempt to quantify externalized costs and associated unmitigated damages; rather, it utilizes available spill volume and cleanup cost data to evaluate internalized costs, from which a comparative assessment of externalized costs may be made.

### F.1 Types of Water and Soil Impacts

Spilled petroleum affects many aspects of the environment, including marine waters, coastline, soil, surface water bodies, groundwater supplies, and air. There are many opportunities for spills to occur along the petroleum distribution chain, and spills can be damaging in each of petroleum's many forms: crude oil, refined gasoline and diesel fuels, and additives such as MTBE. Oil pollution in the form of land- and marine-based spills poses a serious threat not only to the environment, but also to public and commercial property and interests.

Impacts to marine environments are often high-profile events, such as the Exxon Valdez spill in Alaska, or the more recent Prestige spill off the coast of Spain. Spills in the open ocean are often difficult to contain, as they are subject to prevailing winds and ocean currents. Petroleum spills can impact environmental receptors such as kelp beds and associated fish and animal life – animals such as otters, and birds such as brown pelicans, gulls, cormorants and murres can be oiled and potentially die. Marine spills that reach and contaminate the coastline can have not only environmental impacts, but also commercial impacts to tourism and industry, and public health impacts in residential coastal areas.

Land-based spills impacting soil not only have environmental ramifications, but also can damage public and private properties. Petroleum spills initially impacting soil also have the potential to migrate downward or laterally, and impact groundwater and surface water, or affect air quality by volatilizing beneath an enclosed space.

Petroleum released to surface water bodies can impact wildlife such as fish, amphibians, bird and animal life. Moving bodies of water can transport contamination over a wide area. Public health is impacted in the event a petroleum release occurs to a drinking water supply.

Groundwater supplies can be contaminated by releases to adjacent surface water bodies and soil. Depending on the nature of the petroleum product or additive, it can accumulate and travel in a layer on top of the water table, or in solution after dissolving. A threat to public health can result if volatilization from a shallow water table occurs to enclosed structures. A considerable threat to public health occurs in the event that a petroleum release impacts an aquifer utilized as a public drinking water supply.

## F.2 Petroleum Spills

To evaluate spills of petroleum imported into California, it is helpful to first examine California's petroleum distribution system. Imported petroleum arrives via both marine tanker (crude and refined products) and interstate pipeline (refined products only). Petroleum arriving by marine tanker is offloaded at the marine terminal to storage tanks or to feeder pipelines. Petroleum is transported by tanker truck or feeder pipeline to refineries. Crude and refined products are stored in tanks at the refinery. Refined products are transported from the refinery via tanker truck or terminal pipeline. Refined petroleum products are stored in above and underground storage tanks at commercial and private dispensing facilities.

There is a distinct risk of petroleum spills at each point along the distribution chain. The following subsections examine the mechanisms and possible effects of potential petroleum spills. This appendix includes an evaluation of existing spill volume and cleanup cost data for each of these dominant distribution points, and estimated cleanup costs per gallon of petroleum spilled. Additionally, an estimated cost for cleanup of spilled petroleum was estimated for each gallon of each fuel consumed in California.

### F.2.1 Open Ocean Marine Spills

Marine oil spills can pose a serious threat to the environment as well as to commercial interests (see Figure F-1). Spills can leave waterways and their surrounding shores uninhabitable for some time. Such spills often result in the loss of plant and animal life. Periodic spill disasters maintain public awareness of these marine events.

**Figure F-1. Beach Cleanup Following Marine Petroleum Spill**

The volume of spills in U.S. waters has been on a steady downward trend since 1973. According to data compiled by the U.S. Coast Guard (USCG), 46.8% of the volume of oil spilled from 1973 to 1999 came from tank vessels (ships/barges); 22.0% from facilities and other non-vessels; 17.5 percent from pipelines; 7.7 percent from mystery spills; 5.9 percent from non-tank vessels. Figure F-2 presents USCG data on the breakdown of marine spill volumes and sources from 1973 – 1999 (USCG 2001).

As evidenced in Figure F-2, the total volume of petroleum spills in U.S. waters is on the decline. In light of this declining trend, more recent data are used to represent the impact of marine spills. Average annual number of spills and average annual total spill volumes based on USCG data for 1994 through 1998 are presented in Table F-1.

Records of spill cleanup costs are kept by the Office of Spill Prevention and Response (OSPR), a division of the U.S. Department of Fish and Game. These records are not comprehensive, but several examples indicate that cleanup costs can be extremely high, and are heavily dependent upon wind and current conditions, and spill proximity to sensitive receptors. For example[1]:

- September 1998 — **3,000 gallons** ISO 180 fuel oil spilled in San Francisco Bay, affecting San Mateo County coast. $1.23M cleanup cost, $9.4M criminal and civil penalties and restoration costs. **~$3,500/gallon cleanup**
- February 1990 — **416,598 gallons** crude spilled off Huntington Beach. $12M to date spent on cleanup, not settled yet. **~$30/gallon cleanup**

[1] Based upon personal communication on 2/20/02 between Robb Barnitt (TIAX) and Dana Michaels (OSPR).

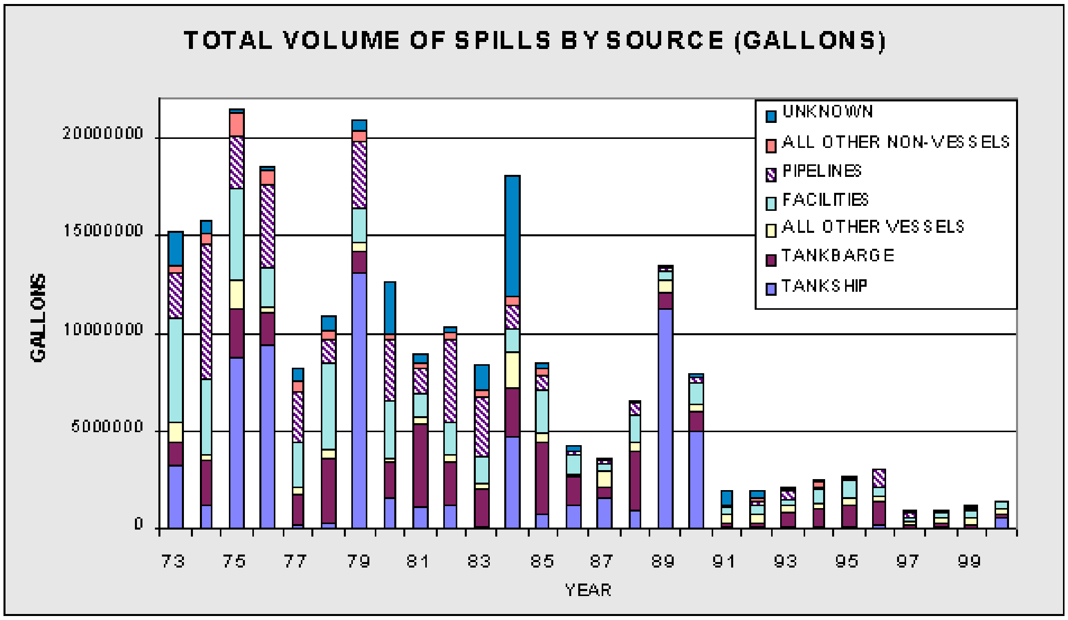



**Figure F-2. Historical Petroleum Marine Spill Volumes by Source — USCG Data**

**Table F-1 Marine Petroleum Spill Frequency[a]**

| | |
|---|---|
| **Average Annual Number of Spills** | 822 |
| **Average Annual Total Volume Spilled** | 60,157 gallons |

[a] USCG 1994 through 1998 data.

According to California State law, the party responsible for a petroleum spill is liable for all incurred cleanup costs. However, in the event that the responsible party cannot be identified, funding for cleanup is provided by the Oil Spill Liability Trust Fund (OSLTF), which was created in 1991. The OSLTF was established using a $0.25 per barrel fee levied upon crude oil transported into or out of California marine waters. Once the OSLTF accumulated $50M in funds, the fee was reduced to $0.04 per barrel crude. The OSLTF is available to fund OSPR, and also to assist in spill cleanup costs. The U.S. Coast Guard manages the Federal Oil Spill Liability Trust Fund (a more complete description of this fund is included in Appendix G. Selected criteria must be met to open this federal fund for spill cleanup. If these criteria are not met, then the state-level OSLTF is utilized.

Estimated cleanup costs of open ocean marine spills provided a basis for calculating the cost associated with each gallon of gasoline and diesel fuel produced annually in California. The following rationale and assumptions apply to this analysis:

- Applied average annual spill volumes of petroleum, according to USCG data for 1994 through 1998
- Utilized the upper limit of estimated cleanup cost per gallon spilled ($3,500/gallon), in an effort to evaluate the “worst-case scenario”
- Assumed all spilled petroleum is crude oil
- Assumed that 72 percent of PAD V production volumes apply to California, as presented by the Energy Information Administration (EIA)
- As presented in EIA 2000, applied California refinery production values of 45.7 and 18.5 percent of total refined volumes processed into gasoline and diesel, respectively. This allows an estimate of fuel volumes to which spilled crude translates.
- Assumed that cleanup costs would follow the same refinery production breakdown of 45.7 percent (gasoline) and 18.5 percent (diesel) of the total annual spill cleanup cost
- Cleanup of spills and other spill-related compensation falls on the responsible party. It is therefore assumed that the calculated costs are internalized to the petroleum pricing structure.

The corresponding cleanup costs are presented in Table F-2.

**Table F-2. Estimated Open Ocean Marine Cleanup Costs Per Gallon of Fuel Produced in California**

| Spill Parameter | Cleanup Cost Calculation |
|---|---|
| Average annual spill volume (gal) | 60,157 |
| Equivalent spill volume — gasoline (gal) | 27,492 |
| Equivalent spill volume — diesel (gal) | 11,129 |
| Cleanup cost ($/gal spilled) | $3,500 |
| Annual spill cleanup cost | $210,548,100 |
| Estimated cleanup cost — gasoline | $96,220,482 |
| Estimated cleanup cost — diesel | $ 38,951,399 |
| CA annual gasoline produced (gal) (EIA 2000) | 15,020,570,880 |
| CA annual diesel produced (gal) (EIA 2000) | 5,165,324,640 |
| Cleanup cost per gallon consumed — gasoline | $0.0064 |
| Cleanup cost per gallon consumed — diesel | $0.0075 |

### F.2.2 Marine Terminal Spills

Petroleum spills can occur during delivery and offloading of ocean tankers at marine terminals. The potential for a spill exists at several points, including:

- Navigation into port
- Cargo offload

- Transfer to tanker truck transport
- Transfer to feeder pipelines

The USCG keeps records specific to the total number and volumes of spills occurring in marine waters. The California State Lands Commission – Marine Terminals Division, keeps a subset of this information, which is specific to spills occurring in marine terminals. The State Lands Commission (SLC) spills database encompassing 1999 through 2001, which contains spill volumes, cleanup costs (if any), and associated federal and/or state fines provided data for evaluating marine terminal spills. According to SLC staff, the spills database is not comprehensive, in that it does not include data for every marine terminal spill. Therefore, the cleanup costs listed in the database should be viewed as a conservative, lower bound data set. The SLC data include petroleum products spilled; and include unrefined crude, gasoline, diesel, jet fuel, and other refined petroleum products. According to federal and state law, cleanup costs are to be paid by the responsible party.

Table F-3 presents a summary of the SLC data, and our estimated cleanup cost per gallon spilled.

**Table F-3. Marine Terminal Petroleum Spill Annual Averages**

| Spill Parameter | Annual Averages | Source |
|---|---|---|
| Petroleum products spill volume | 3,357 gallons | State Lands Commission Marine Terminal data 1999 through 2001 |
| Federal/State fines | $6,417 | State Lands Commission Marine Terminal data 1999 through 2001 |
| Cost of cleanup | $16,698 | State Lands Commission Marine Terminal data 1999 through 2001 |
| Spilled petroleum product cleanup cost | $5.28 per gallon | TIAX Calculation |
| Spilled petroleum product cleanup cost (including fines) | $7.31 per gallon | TIAX Calculation |

TIAX estimated the cleanup costs of marine terminal spills, and calculated the cost associated with each gallon of gasoline and diesel fuel produced annually in California. The following rationale and assumptions apply to this analysis:

- Applied average annual spill volumes of petroleum, according to State Lands Commission data for 1999 through 2001
- Utilized the higher cleanup cost figure ($7.31/gallon) calculated for cleanup costs including federal and state fines
- Assumed all spilled petroleum is crude oil
- Assumed that 72 percent of PAD V production volumes apply to California, as presented in EIA 2000

- As presented in EIA 2000, applied California refinery production values of 45.7 and 18.5 percent of total refined volumes are processed into gasoline and diesel, respectively. This allows an estimate of fuel volumes to which spilled crude translates.
- Assumed that cleanup costs would follow the same refinery production breakdown of 45.7 percent (gasoline) and 18.5 percent (diesel) of the total annual spill cleanup cost
- Cleanup of spills and other spill-related compensation falls on the responsible party. It is therefore assumed that the calculated costs are internalized to the petroleum pricing structure.

Estimated cleanup costs are presented in Table F-4.

**Table F-4. Estimated Marine Terminal Cleanup Costs Per Gallon of Fuel Produced in California**

| Spill Parameter | Marine Terminal Calculation |
|---|---|
| Average annual spill volume (gal) | 3,357 |
| Equivalent spill volume — gasoline (gal) | 1,534 |
| Equivalent spill volume — diesel (gal) | 621 |
| Annual spill cleanup cost (including fines) | $23,115 |
| Estimated cleanup cost — gasoline | $10,563 |
| Estimated cleanup cost — diesel | $4,276 |
| CA annual gasoline produced (gal) (EIA 2000) | 15,020,570,880 |
| CA annual diesel produced (gal) (EIA 2000) | 5,165,324,640 |
| Cleanup cost per gallon consumed — gasoline | $0.0000007 |
| Cleanup cost per gallon consumed — diesel | $0.0000008 |

### F.2.3 Pipeline Spills

Pipelines transport about 65 percent of the crude oil and refined petroleum products produced in the United States (CEERT 2000). These pipelines carry crude oil to refineries and refined products to distribution points after refining. Pipeline ruptures can release crude or refined petroleum products, with the potential to impact soil, surface water bodies, and groundwater. Commercial and private property can also be damaged.

The Department of Transportation (DOT) Office of Pipeline Safety (OPS) enforces pipeline safety regulations and compiles a database of spill volumes and associated property damages. According to OPS data, the number of spills has decreased nationally. However, spill volumes and property damages have not decreased significantly. It can be assumed that this fact is due to increased petroleum demand. Figure F-3 presents national DOT OPS data from 2001. Spill volumes refer to all petroleum products.

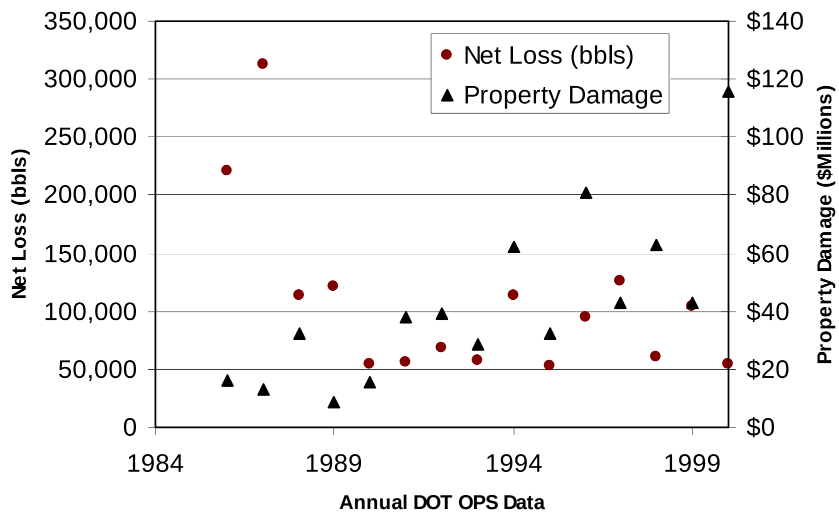



**Figure F-3. Historical Data — Pipeline Spill Volumes and Associated Property Damage**

Based upon 1984 through 1999 DOT OPS data specific to California, TIAX determined annual averages for spill incidents, volumes, and associated property damage costs. Table F-5 presents this information.

**Table F-5. Pipeline Petroleum Spill Annual Averages**

| Spill Parameter | Annual Averages | Source |
|---|---|---|
| Number of accidents per year | 31 | DOT OPS Data CA 1984-1999 |
| Average spill size (gal) | 14,815 | DOT OPS Data CA 1984-1999 |
| Property damage | $9,126,581 | DOT OPS Data CA 1984-1999 |
| Fatalities | 1.94 | DOT OPS Data CA 1984-1999 |
| Injuries | 8.13 | DOT OPS Data CA 1984-1999 |
| Gross loss (bbls) | 10,913 | DOT OPS Data CA 1984-1999 |
| Gross loss (gal) | 458,338 | DOT OPS Data CA 1984-1999 |
| Spilled petroleum product cleanup cost | $19.91 per gallon | TIAX Calculation |

TIAX estimated the cleanup costs of pipeline spills, and calculated the cost associated with each gallon of gasoline and diesel fuel produced annually in California. The following rationale and assumptions apply to this analysis:

- Applied average annual spill volumes of petroleum, according to DOT OPS data for 1984 through 1999
- Utilized the estimated cleanup cost figure of $19.91 per gallon
- Assumed all spilled petroleum is refined product
- As presented in EIA 2000, California refinery production values of 45.7 and 18.5 percent of total refined volumes are processed into gasoline and diesel, respectively. Applied like estimated volumes to determine amount of spilled refined products from pipelines.
- Assumed that cleanup costs would follow the same ratio of 2.47:1 for gasoline to diesel
- Cleanup of spills and other spill-related compensation falls on the responsible party. It is therefore assumed that the calculated costs are internalized to the petroleum pricing structure.
- Combined estimated annual cleanup costs and average annual property damage to estimate internalized cleanup cost per gallon of gasoline and diesel
- As mentioned previously, in this evaluation human death and injury are considered to be inestimable externalities. Typically, pain and suffering costs to the injured party or family are not internalized. However, a portion of legal compensation or liability payments may in fact be internalized. The evaluation does not seek to separate internalized or externalized costs as related to human death or injury. However, if we use the ARB or EPA methodology to value premature mortality, the 1.94 fatalities would add an additional $9.2M ($4.73M × 1.94) to the annual cost. Additional costs shall also be included for injuries.

Estimated cleanup costs are presented in Table F-6.

**Table F-6. Estimated Pipeline Spill Cleanup Costs Per Gallon of Fuel Produced in California**

| Spill Parameter | Pipeline Calculation |
|---|---|
| Average annual spill volume (gal) | 488,894 |
| Equivalent spill volume — gasoline (gal) | 348,013 |
| Equivalent spill volume — diesel (gal) | 140,881 |
| Annual spill cleanup cost | $18,861,602 |
| Estimated cleanup cost — gasoline | $13,426,405 |
| Estimated cleanup cost — diesel | $5,435,197 |
| CA annual gasoline produced (gal) (EIA 2000) | 15,020,570,880 |
| CA annual diesel produced (gal) (EIA 2000) | 5,165,324,640 |
| Cleanup cost per gallon consumed — gasoline | $0.00089 |
| Cleanup cost per gallon consumed — diesel | $0.00105 |

### F.2.4 Refinery Spills

Crude oil delivered to refineries is converted to gasoline, diesel, and other fuels and petroleum products. Refineries use physical, thermal, and chemical separation techniques, which require extremely high temperatures and pressures to separate crude oil into other products. Approximately 90 percent of all petroleum products that are produced in the United States are fuels. Gasoline and diesel account for 45.7 and 18.5 percent, respectively of the total output from refineries (EIA 2000). Refining causes air and water pollution and produces hazardous wastes, and oil refineries use and release toxic chemicals into the environment (CEERT).

In addition to environmental impacts, refineries are also subject to lethal accidents involving workers. These accidents, often involving explosions and fires, are dangerous to those working on the site and to surrounding residents. Examples of recent refinery accidents include (CEERT):

- February 1, 1996: A hydrogen unit at a Shell refinery exploded, igniting a fire and causing minor injuries to two workers
- August 22, 1994: Unocal's Rodeo refinery started releasing Catacarb, a toxic catalyst that can cause skin burning, shortness of breath and headaches. The leak continued for 16 days before the company notified state and federal authorities. Almost 600 residents and 75 employees reported symptoms in the days following the company's disclosure. Unocal later pleaded no contest to 12 criminal counts by the state and agreed to pay a $3M fine.
- April 10, 1989: Three workers were burned in a fire and explosion at the Chevron refinery in Richmond

According to the EIA 2000, there are currently 23 refineries operating in California (see Figure F-4).

Spills of crude and refined products can occur during the refining process, as well as during storage. Spills during storage may occur prior to refining, or after refining has occurred, but before transport from the refinery itself.

Limited data are available on spills from refineries. It has been estimated that an average size refinery releases 10,000 gallons of oily liquid per day to the air, water and land (Environmental Defense Fund 1995). It is not known what the recovered and remediated spill volumes are from refineries. However, according to federal and state law, cleanup costs are to be paid by the responsible party.

We estimated the cleanup costs of refinery spills, and calculated the cost associated with each gallon of gasoline and diesel fuel produced annually in California. The following rationale and assumptions apply to this analysis:

- Applied estimated daily oily liquid release per refinery of 10,000 gallons
- This spill volume estimate was expanded to an annual figure, and to encompass all 23 California refineries
- Assumed all spilled petroleum is crude

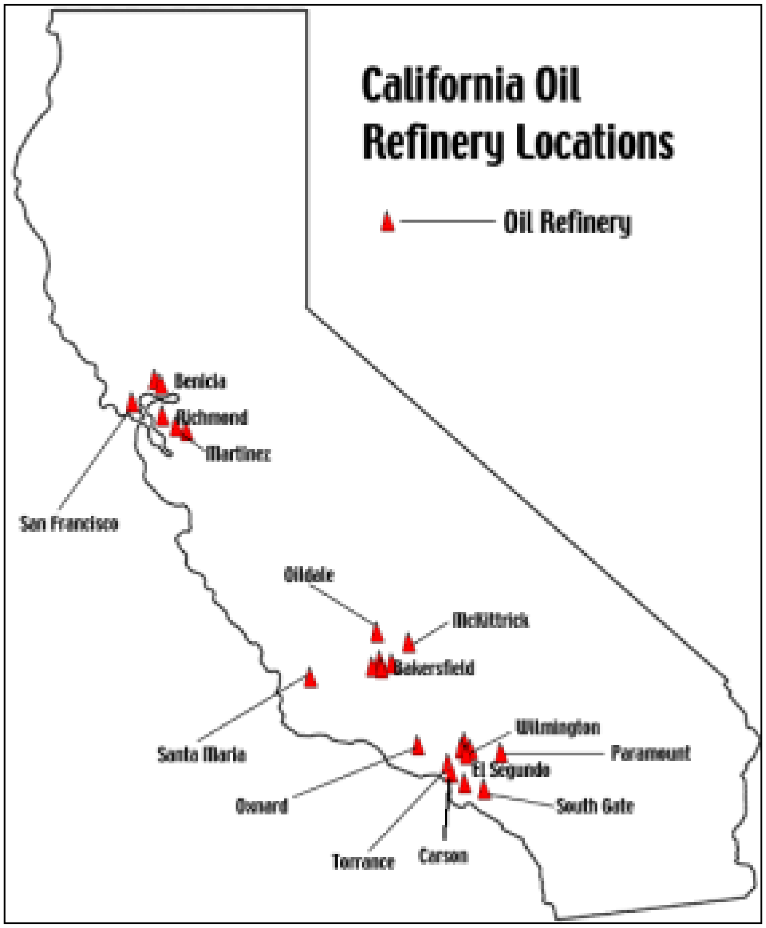



**Figure F-4. California Oil Refinery Locations**

- Utilized the estimated cleanup cost figure of $7.31 per gallon, as estimated for crude oil spills in marine terminals
- Assumed that 72 percent of PAD V production volumes apply to California, as presented in EIA 2000
- As presented in EIA 2000, applied California refinery production values of 45.7 and 18.5 percent of total refined volumes are processed into gasoline and diesel, respectively. This allows an estimate of fuel volumes that spilled crude translates to.
- Assumed that cleanup costs would follow the same refinery production breakdown of 45.7 percent (gasoline) and 18.5 percent (diesel) of the total annual spill cleanup cost
- Cleanup of spills and other spill-related compensation falls on the responsible party. It is therefore assumed that the calculated costs are internalized to the petroleum pricing structure.

Estimated cleanup costs are presented in Table F-7.

**Table F-7. Estimated Refinery Spill Cleanup Costs Per Gallon of Fuel Produced in California**

| Spill Parameter | Refinery Spill Calculation |
|---|---|
| Average annual spill volume (gal) | 83,950,000 |
| Equivalent spill volume — gasoline (gal) | 38,365,150 |
| Equivalent spill volume — diesel (gal) | 15,530,750 |
| Annual spill cleanup cost | $613,674,500 |
| Estimated cleanup cost — gasoline | $280,449,247 |
| Estimated cleanup cost — diesel | $113,529,783 |
| CA annual gasoline produced (gal) (EIA 2000) | 15,020,570,880 |
| CA annual diesel produced (gal) (EIA 2000) | 5,165,324,640 |
| Cleanup cost per gallon consumed — gasoline | $0.0187 |
| Cleanup cost per gallon consumed — diesel | $0.0220 |

### F.2.5 Transportation Spills

Spills of refined fuels gasoline and diesel during transportation can impact soil, surface water, and groundwater. Tanker rollovers can be dangerous to the public, and create road closures.

The U.S. EPA has estimated that petroleum spill volumes from pipelines are 10 to 20 times greater that from tanker truck spills (The Seattle Times). However, truck accidents are 300 times more likely to kill people than pipeline accidents (The Seattle Times). The societal costs of these deaths are not included in this analysis.

Spills of refined gasoline and diesel fuel can occur in many modes during transport to private and commercial distribution centers. Modes of fuel loss during fuel transportation were summarized from previous studies. Table F-8 presents the dominant modes of fuel loss. Approximately 85 percent of the total volumetric loss occur during spillage.

Previously estimated volume losses and California petroleum production values (EIA 2000) provided an estimate of total annual spill volumes during transportation. An estimated annual cost of cleanup was derived using an estimated cleanup cost per spilled gallon. This cleanup cost per gallon is based upon a broad estimate used by TIAX. These estimated spill volumes and cleanup costs are presented in Table F-9.

**Table F-8. Modes of Fuel Loss During Transportation**

| Mode of Fuel Loss During Transportation |
|---|
| • Feedstock transport<br>• Fuel transport<br>• Fuel unloading<br>• Bulk terminal<br>• Truck loading<br>• Truck spillage<br>• Truck exhaust<br>• Truck unloading<br>• Storage tank breathing<br>• Vehicle working loss spillage |

**Table F-9. Estimated Annual Average Transportation Spill Volumes and Costs**

| Spill Parameter | Transportation Spill Calculation |
|---|---|
| % volume loss diesel | 0.0100% |
| % volume loss gasoline | 0.0106% |
| Annual CA diesel production | 5,165,324,640 |
| Annual CA gasoline production | 15,020,570,880 |
| Annual volume loss/spill diesel | 517,864 |
| Annual volume loss/spill gasoline | 1,588,078 |
| Total annual volume loss (gal) | 2,105,942 |
| Estimated cleanup cost per gallon | $30.00 |
| Annual cleanup cost | $63,178,257 |

We estimated the cleanup costs of transportation spills, and calculated the cost associated with each gallon of gasoline and diesel fuel produced annually in California. The following rationale and assumptions apply to this analysis:

- Applied estimated annual spill volumes of petroleum, according to TIAX calculation
- Utilized the estimated cleanup cost figure of $30 per gallon
- Assumed all spilled petroleum is refined product
- As presented in EIA 2000, applied California refinery production gasoline-diesel ratio of 2.47:1 to estimate volumes of spilled refined products from pipelines
- Assumed that cleanup costs would follow the same ratio of 2.47:1 for gasoline to diesel

- Cleanup of spills and other spill-related compensation falls on the responsible party. It is therefore assumed that the calculated costs are internalized to the petroleum pricing structure.

Estimated cleanup costs are presented in Table F-10.

**Table F-10. Estimated Transportation Spill Cleanup Costs Per Gallon of Fuel Produced in California**

| Spill Parameter | Transportation Spill Calculation |
|---|---|
| Annual spill volume (gal) | 2,105,942 |
| Equivalent spill volume — gasoline (gal) | 1,499,089 |
| Equivalent spill volume — diesel (gal) | 606,852 |
| Annual spill cleanup cost | $63,178,257 |
| Estimated cleanup cost — gasoline | $44,972,685 |
| Estimated cleanup cost — diesel | $18,205,573 |
| CA annual gasoline produced (gal) (EIA 2000) | 15,020,570,880 |
| CA annual diesel produced (gal) (EIA 2000) | 5,165,324,640 |
| Cleanup cost per gallon consumed — gasoline | $0.0029941 |
| Cleanup cost per gallon consumed — diesel | $0.0035246 |

### F.2.6 Leaking Underground Storage Tank Spills

Spills of refined gasoline and diesel fuel can occur from Leaking Underground Storage Tanks (LUSTs). These spills can impact soil, and after percolating down to the water table, can impact groundwater. Plumes of contamination can travel on and in groundwater, impacting other regions. Of particular concern is contamination impacting a groundwater aquifer, which is used as a public drinking water supply. The fuel additive MTBE is a considerable threat to groundwater resources, as it dissolves in water more readily than other gasoline constituents.

The California EPA and State Water Board oversee the LUST Cleanup Fund. This fund has been in operation for 10 years, and provides reimbursement for LUST cleanup. The LUST Cleanup Fund is comprised of an annual total of $195M, accrued by assessing a fee of $0.012 per gallon of fuel, paid by UST owners. The Fund can not be applied to surface spills (i.e., tanker rollovers), or bulk terminals, but is specific to fleet and commercial fuel dispensing facilities. Typically, remedial costs reimbursed by the LUST Cleanup Fund include LUST excavation and removal, and soil and groundwater remediation. According to Alan Patten of the California EPA, the average LUST cleanup costs about $150K, but the range is $20K to $1.5M.

Only a portion of the claims made requesting reimbursement are funded, and a portion of those funded claims have been closed to date. Table F-11 presents some basic information with regard to the LUST Cleanup Fund's progress to date.

**Table F-11. LUST Cleanup Fund Accomplishments to Date**

| LUST Parameter | CA LUST Fund |
|---|---|
| Number of claims | 17,000 |
| Number of claims funded | 9,000 |
| Number of cases closed | 4,500 |
| Average claims per year | 1,700 |
| Number of claims funded per year | 900 |
| Total annual funding monies | $195,000,000 |
| Average cost cleanup per case | $150,000 |

We estimated the cleanup costs of LUST spills, and calculated the cost associated with each gallon of gasoline and diesel fuel produced annually in California. The following rationale and assumptions apply to this analysis:

- Assumed total available funding of $195M applied to LUST cleanup annually
- Assumed all spill product is gasoline and diesel
- Assumed funding applied to gasoline and diesel followed ratio of gasoline and diesel (2.47:1) produced annually in California
- Estimated cleanup cost per gallon consumed of gasoline and diesel based solely upon annual monies available in the LUST Cleanup Fund
- Cleanup of spills and other spill-related compensation falls on the responsible party. It is therefore assumed that the calculated costs are internalized to the petroleum pricing structure.

Estimated cleanup costs are presented in Table F-12.

**Table F-12. Estimated LUST Spill Cleanup Costs Per Gallon Fuel of Produced in California**

| Spill Parameter | Spill Cleanup Calculation |
|---|---|
| Annual spill cleanup cost | $195,000,000 |
| Estimated cleanup cost — gasoline | $145,101,877 |
| Estimated cleanup cost — diesel | $49,898,123 |
| CA annual gasoline produced (gal) (EIA 2000) | 15,020,570,880 |
| CA annual diesel produced (gal) (EIA 2000) | 5,165,324,640 |
| Cleanup cost per gallon consumed — gasoline | $0.0097 |
| Cleanup cost per gallon consumed — diesel | $0.0097 |

## F.3 Summary of Water and Soil Impacts

Petroleum spills are responsible for considerable environmental damage to water, soil and air. Not only are the environment, plants and animals impacted, but commercial activities are affected, as is public health.

The costs of petroleum spill cleanup were estimated at several of the dominant points in the petroleum distribution chain. These annual costs are significant, but are considered to be internalized, and are likely included in the petroleum pricing structure. A summary total of these estimated spill volumes and cleanup costs are presented in Table F-13.

**Table F-13. Estimated Total Annual Spill Cleanup Costs Per Gallon Fuel Produced in California**

| Spill Parameter | Spill Cleanup Calculation |
|---|---|
| Annual spill volume (gal) | 86,608,350 |
| Equivalent spill volume — gasoline (gal) | 40,241,279 |
| Equivalent spill volume — diesel (gal) | 16,290,233 |
| Annual spill cleanup cost | $1,101,285,574 |
| Estimated cleanup cost — gasoline | $580,181,258 |
| Estimated cleanup cost — diesel | $226,024,350 |
| CA annual gasoline produced (gal) (EIA 2000) | 15,020,570,880 |
| CA annual diesel produced (gal) (EIA 2000) | 5,165,324,640 |
| Cleanup cost per gallon consumed — gasoline | $0.039 |
| Cleanup cost per gallon consumed — diesel | $0.044 |

Note: Estimated spill volumes do not include an estimate for LUSTs.

Figures F-5 through F-7 illustrate the estimated annual spill volumes and internalized cleanup costs associated with each dominant petroleum distribution point. It is important to note that no spill volume estimate was made for LUSTs. In general, the spill volumes and cleanup costs are dominated by the refinery estimates. However, these volume and costing estimates are based upon available sources, and not a comprehensive database.

Internalized cost data presented are based upon reported expenditures. It is unlikely that spill sites are returned to their original state following cleanup efforts. These unmitigated damages are considered societal and environmental external costs, and were not explicitly calculated in this evaluation. These societal and environmental costs are associated with petroleum use, and are difficult to assign a dollar figure to. These societal costs might include:

- Deaths of animals and plants, and destruction of habitat
- Loss of blue sky due to air pollution
- Impacted public health due to multimedia contamination

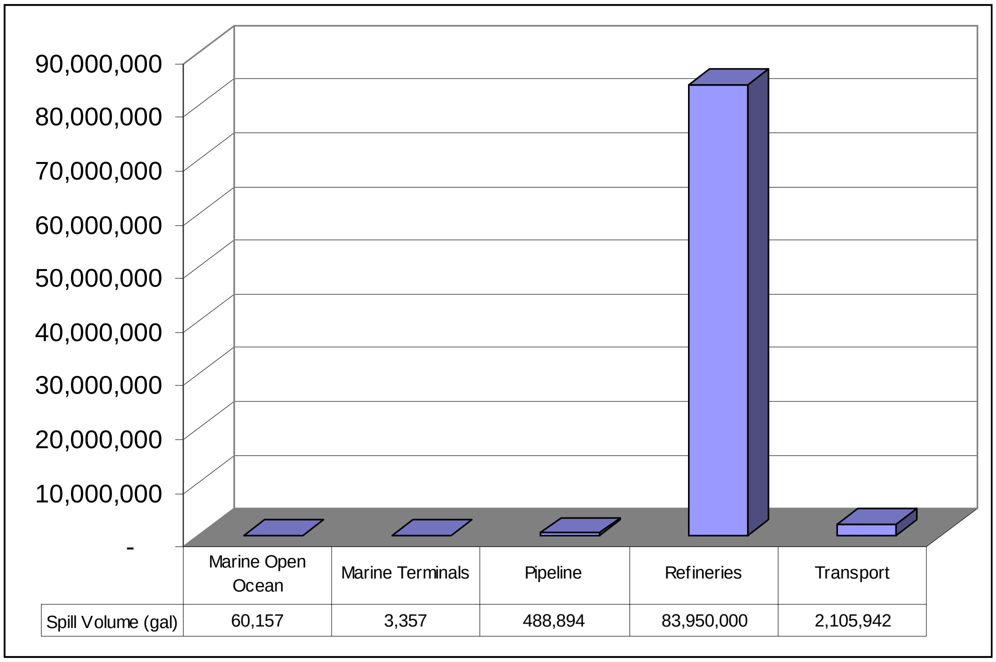



**Figure F-5. Estimated Annual Petroleum Spill Volumes**

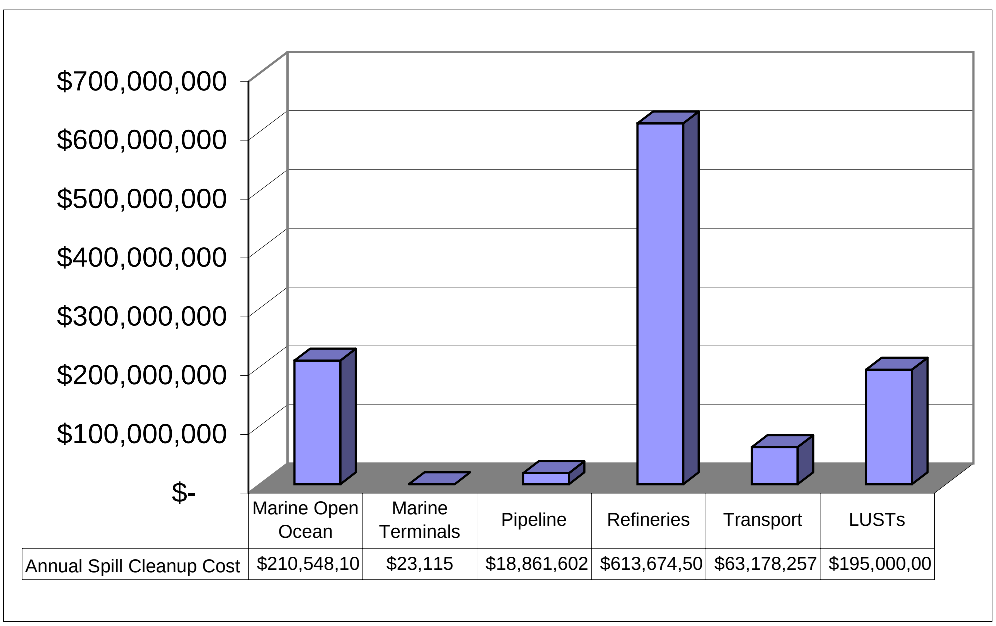
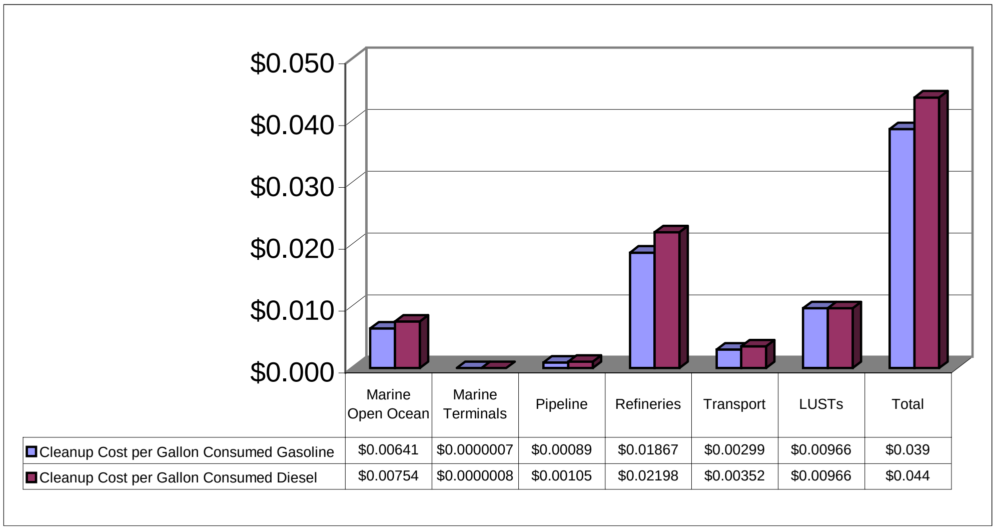



**Figure F-6. Estimated Annual Petroleum Spill Cleanup Costs**




| | Marine Open Ocean | Marine Terminals | Pipeline | Refineries | Transport | LUSTs | Total |
|---|---|---|---|---|---|---|---|
| Cleanup Cost per Gallon Consumed Gasoline | $0.00641 | $0.0000007 | $0.00089 | $0.01867 | $0.00299 | $0.00966 | $0.039 |
| Cleanup Cost per Gallon Consumed Diesel | $0.00754 | $0.0000008 | $0.00105 | $0.02198 | $0.00352 | $0.00966 | $0.044 |

**Figure F-7. Estimated Cleanup Costs Per Gallon of Fuel Consumed in California**

Additionally, as noted in previous sections, human injury and deaths caused by petroleum spills or related accidents bridge internalized and externalized costs. Internalized costs may include compensation, legal and liability payments, while pain and suffering costs should be considered an externality.

This section evaluates petroleum spill and property damage internalized costs, based upon limited data. As presented in Figure F-7 the calculated internalized costs for spill cleanup are $0.039 and $0.044 respectively, per gallon of gasoline and diesel fuel consumed. Further study is required to estimate the externalized costs associated with petroleum usage, but TIAX projects that externalized costs are at least equal to those internalized costs.

By reducing petroleum dependency, significant savings may be realized both in internalized and externalized multimedia petroleum spill cleanup costs.

## F.4 References for Appendix F

U.S. Coast Guard, Pollution Incidents In and Around U.S. Waters, Internet versions updated August 2001 (http://www.uscg.mil/hq/gm/nmc/response/stats/summary.htm ).

Energy Information Administration (EIA) Petroleum Supply Annual, Volume 1, 2000 - http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html.

CEERT, *Crude Reckoning: The Impact of Petroleum on California's Public Health and Environment*, Center for Energy Efficiency and Renewable Technologies, August 2000.

*Ranking Refineries*, Environmental Defense Fund, November 1995.

*The Seattle Times*, June 17, 1999.

## Appendix G.  Spill Liability

Section 1002 of the Oil Pollution Act of 1990 (OPA) holds facilities that cause oil spills responsible for cleanup costs and damages resulting from the spill. The law limits the liability of an onshore facility owner or operator to $350 million per spill unless the oil spill resulted from gross negligence, willful misconduct, or a violation of federal regulations.  In these cases liability is unlimited. The unlimited liability provision also applies to the owner or operator in cases where the negligence, misconduct, or violation results from a responsible party's agent, employee, or person contracting with the owner or operator.

A responsible party can absolve its liability for the response costs and damages of an oil spill if the spill results from an act of God, an act of war, or an act or omission of a third party. In these cases, the facility owner or operator is released from the strict liability provisions. In the event that the responsible party either is unknown or is absolved of its liability, the OPA established the Oil Spill Liability Trust Fund to help pay for cleanup costs, oil spill damages, and certain operational expenses incurred as a result of an oil spill response.  In addition to the liability provisions, facility owners and operators who discharge oil may also be subject to administrative or judicial penalties.

### G.1 Oil Spill Liability Trust Fund

Under the OPA, the owner or operator of a facility from which oil is discharged (also known as the responsible party) is liable for the costs associated with the containment or cleanup of the spill and any damages resulting from the spill.  The EPA's first priority is to ensure that responsible parties pay to clean up their own oil releases.  However, when the responsible party is unknown or refuses to pay, funds from the Oil Spill Liability Trust Fund can be used to cover removal costs or damages resulting from discharges of oil.

The primary source of revenue for the fund is a 5 cents per barrel fee on imported and domestic oil. Collection of this fee ceased on December 31, 1994 due to a “sunset” provision in the law. Other revenue sources for the fund include interest on the fund, cost recovery from the parties responsible for the spills, and any fines or civil penalties collected.  The fund is administered by the U.S. Coast Guard's National Pollution Funds Center (NPFC).

The fund can provide up to $1 billion for any one oil pollution incident, including up to $500 million for the initiation of natural resource damage assessments and claims in connection with any single incident. The main uses of fund expenditures are:

- State access for removal actions
- Payments to federal, state, and Indian tribe trustees to carry out natural resource damage assessments and restorations
- Payment of claims for uncompensated removal costs and damages
- Research and development and other specific appropriations

## G.2 Penalties Under the Law

Under the Clean Water Act, as amended by the OPA, the EPA has greater authority to pursue administrative, judicial, and criminal penalties for violations of the regulations and for discharges of oil and hazardous substances. Under the new penalty system, three different courses of action are available to the EPA in the event of a spill: (1) the EPA may assess an administrative penalty against the facility; (2) the EPA may seek a judicial penalty against the facility in the federal court system; or (3) the EPA may seek a criminal action against the facility in the federal court system.

### G.2.1 Administrative Penalties

The EPA may assess administrative penalties against oil or hazardous substance dischargers as well as facility owners or operators who fail to comply with the Oil Pollution Prevention regulation. The administrative penalty amounts that violators must pay have increased under the OPA, and a new system of administrative penalties was created based on two classes of violations. Class I violations may be assessed an administrative penalty up to $10,000 per violation, but no more than $25,000 total. Class II violations, which are more serious, may be assessed up to $10,000 per day, but no more than $125,000 total. However, a facility that has been assessed a Class II administrative penalty cannot be subject to a civil judicial action for the same violation.

### G.2.2 Judicial Penalties

Judicial penalties may be assessed against facility owners or operators who discharge oil or hazardous substances, who fail to properly carry out a cleanup ordered by the EPA, or who fail to comply with the Oil Pollution Prevention regulation. Courts may assess judicial penalties for discharges as high as $25,000 per day or up to $1,000 per barrel of oil spilled (or $1,000 per reportable quantity of hazardous substance discharged.) For those discharges that result from gross negligence or willful misconduct, the penalties increase to no less than $100,000 and up to $3,000 per barrel of oil spilled (or per unit of reportable quantity of hazardous substance discharged). Owners and operators of facilities who fail to comply with an EPA removal order may be subject to civil judicial penalties up to $25,000 per day, or three times the cost incurred by the Oil Spill Liability Trust Fund, as a result of their failure to comply. Finally, if the facility fails to comply with its EPA-approved SPCC plan, the civil judicial penalty may reach $25,000 per day of violation.

### G.2.3 Criminal Penalties

The EPA may pursue criminal penalties against facility owners or operators who fail to notify the appropriate federal agency of an oil discharge. Specifically, under the Clean Water Act, the federal government can impose a penalty up to a maximum of $250,000 for an individual or $500,000 for a corporation, and a maximum prison sentence of five years.

(Source: www.epa.gov )

## Appendix H. Supplemental DENB Analysis Results

In addition to the results presented in Section 4, additional results of the DENB analysis are presented here. Figures H-1 through H-6 are for the Improved Fuel Economy Options (Group 1A).

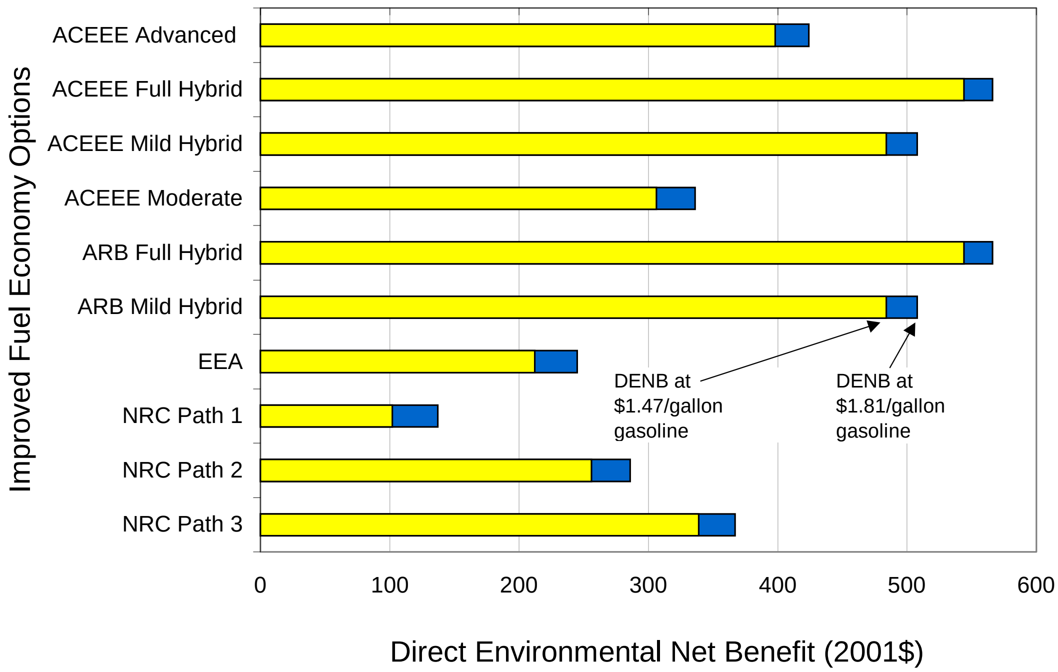



**Figure H-1. Group 1A Range of DENB in 2020**

The darker values correspond to a range of retail gasoline prices ($1.47/gallon to $1.81/gallon gasoline).

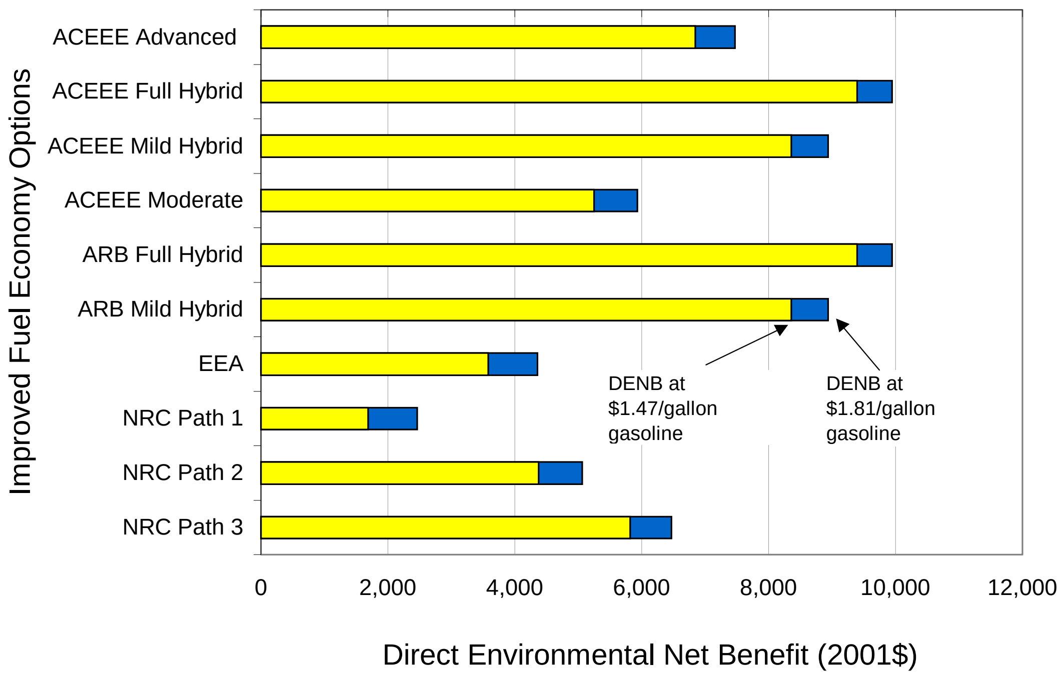



**Figure H-2. Group 1A Range of DENB in 2002-2030**

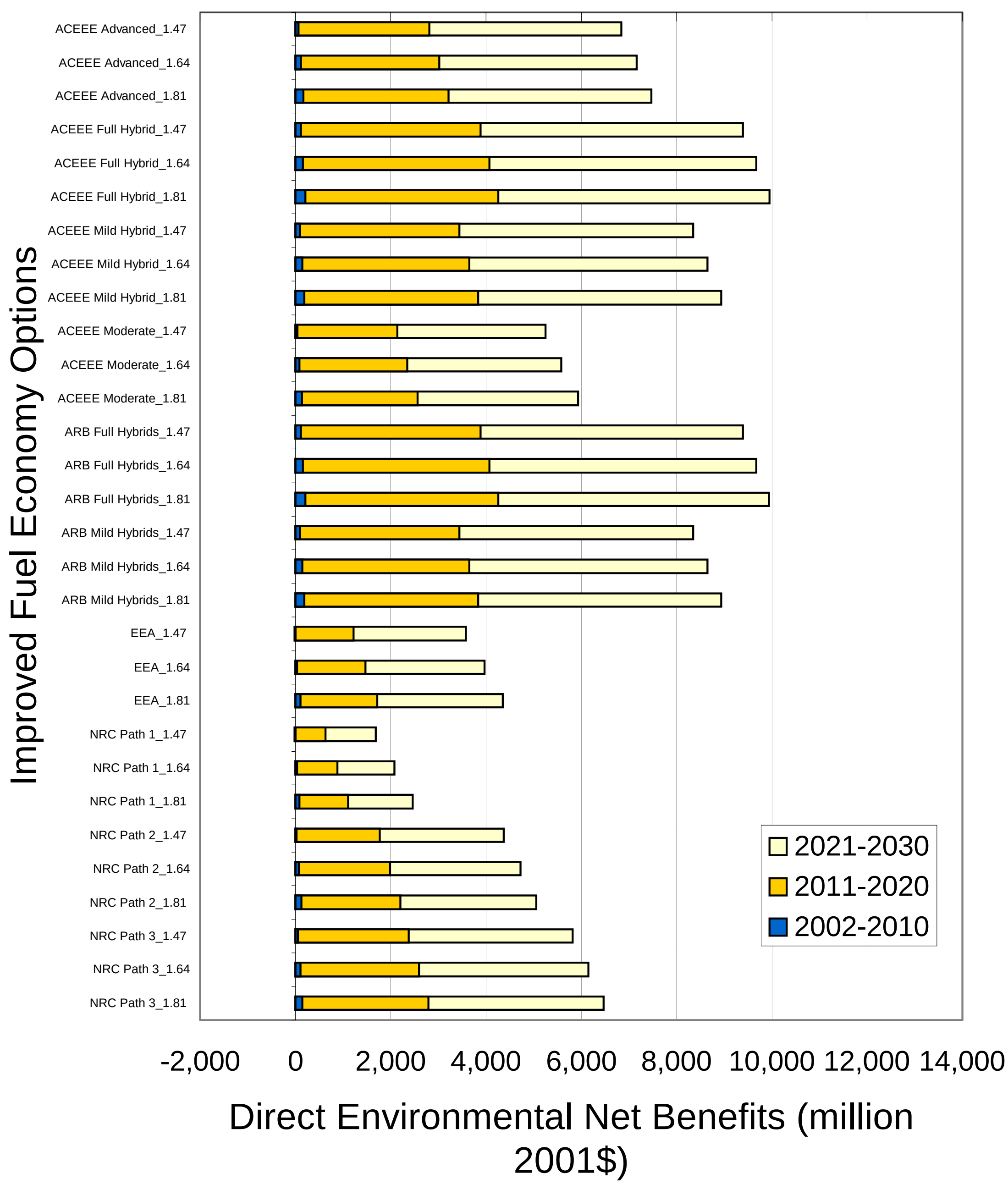



**Figure H-3. Group 1A DENB FOR 2002-2030**

Note that the suffix "_1.XX" in the options represented above refers to the assumed retail price of gasoline for that option. For example, "ACEEE Advanced_1.47" refers to the ACEEE Advanced Improved Fuel Economy option where the retail price of gasoline is $1.47/gallon.

The DENB for each option was normally calculated using a 5% annual discount. For comparison, the DENB was also calculated with a 0% annual discount. Options with an annual discount factor between 0 and 5% will have a DENB between the default and "No Discount" cases.

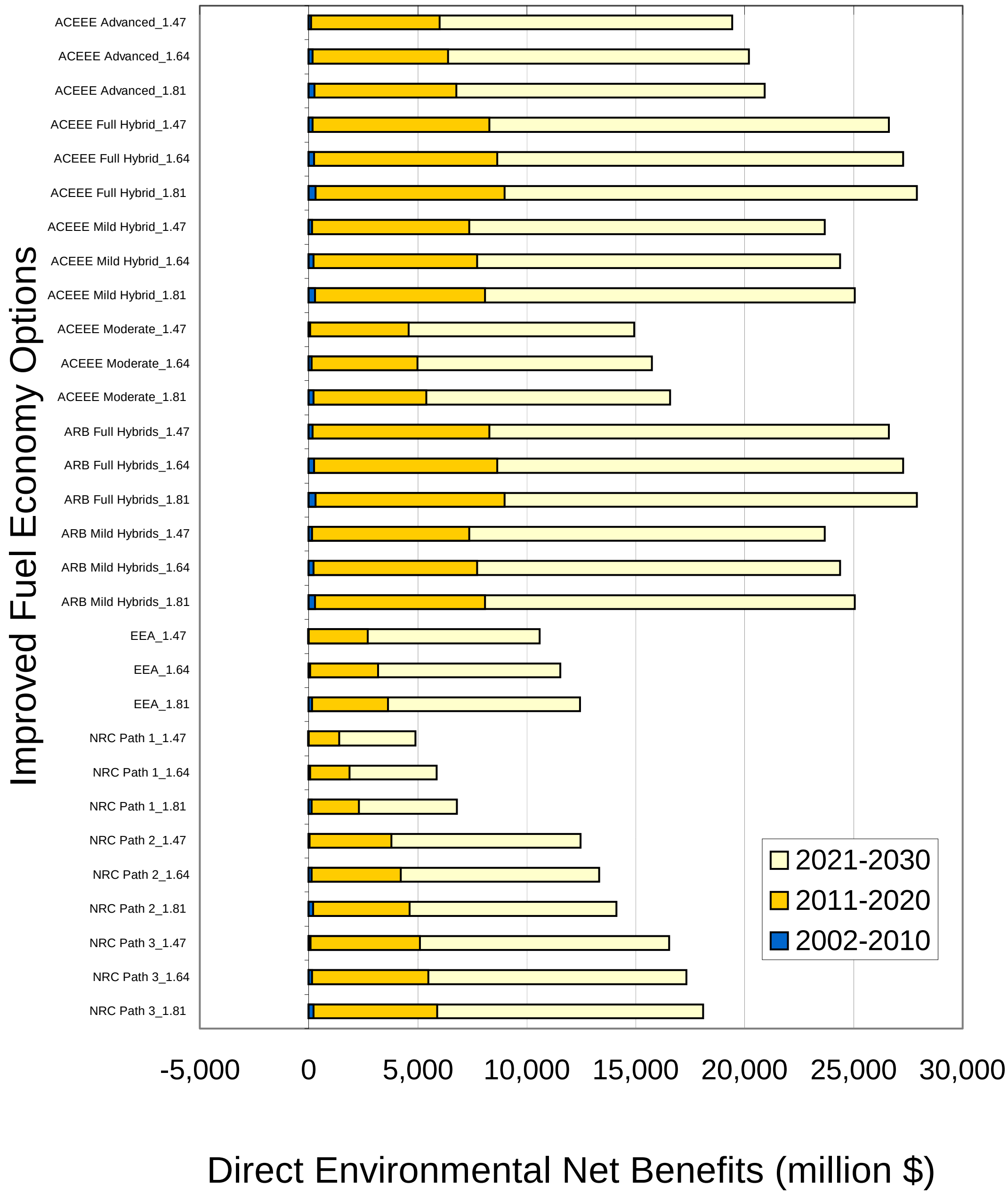



**Figure H-4. Group 1A DENB for 2002-2030 (No Discount)**

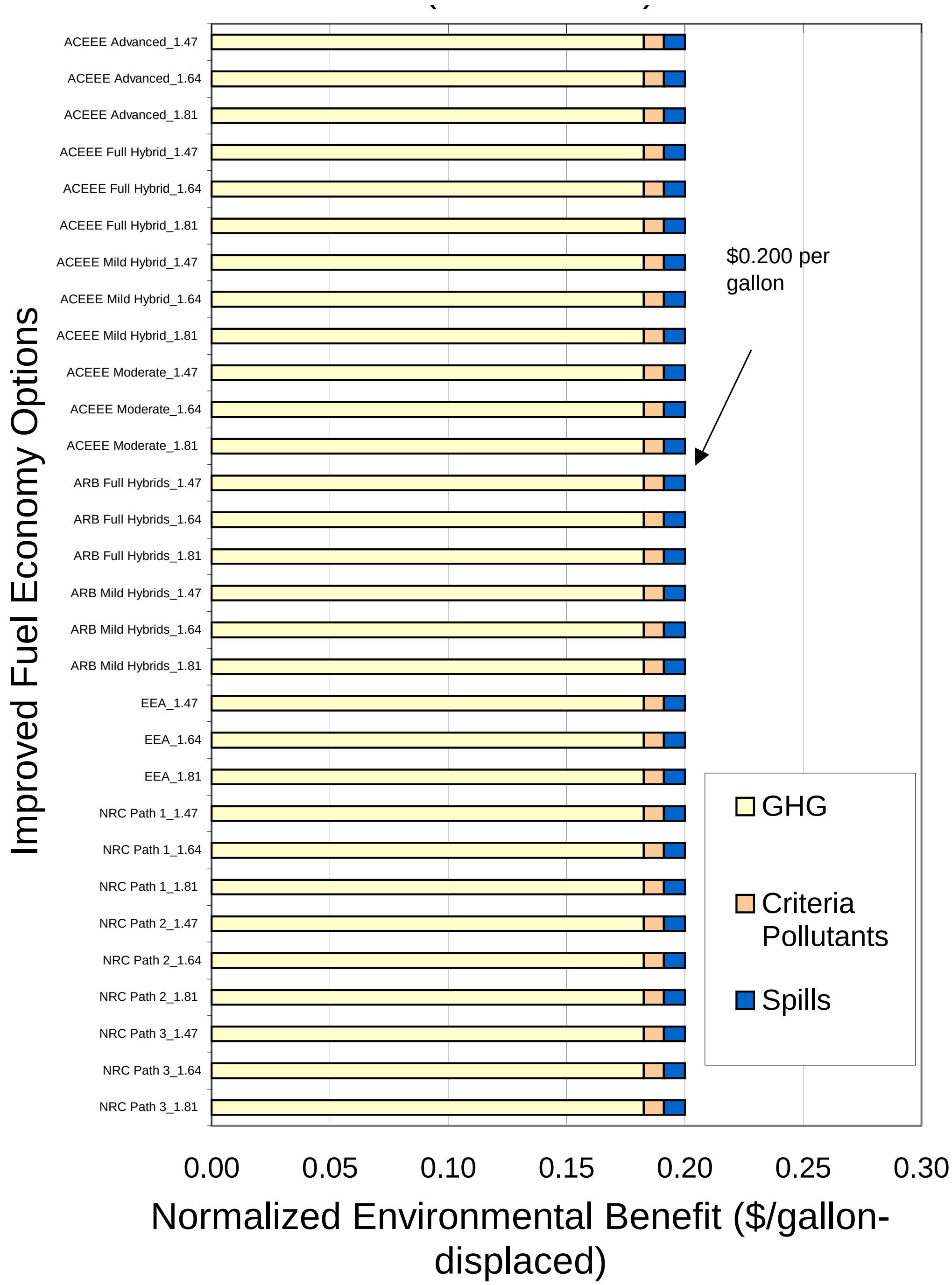



**Figure H-5. Group 1A DENB per Gallon Displaced (No Discount)**

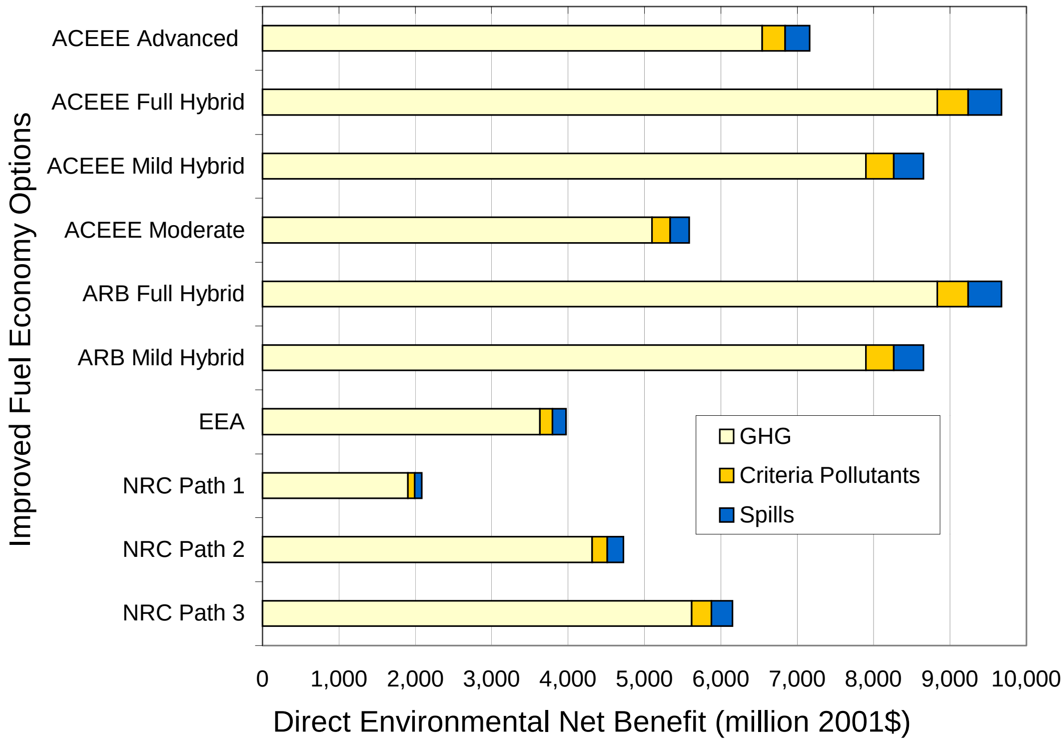



**Figure H-6. Group 1A Speciated DENB for 2002-2030**

Figures H-7 through H-10 present additional DENB results for the other Fuel Efficiency options.

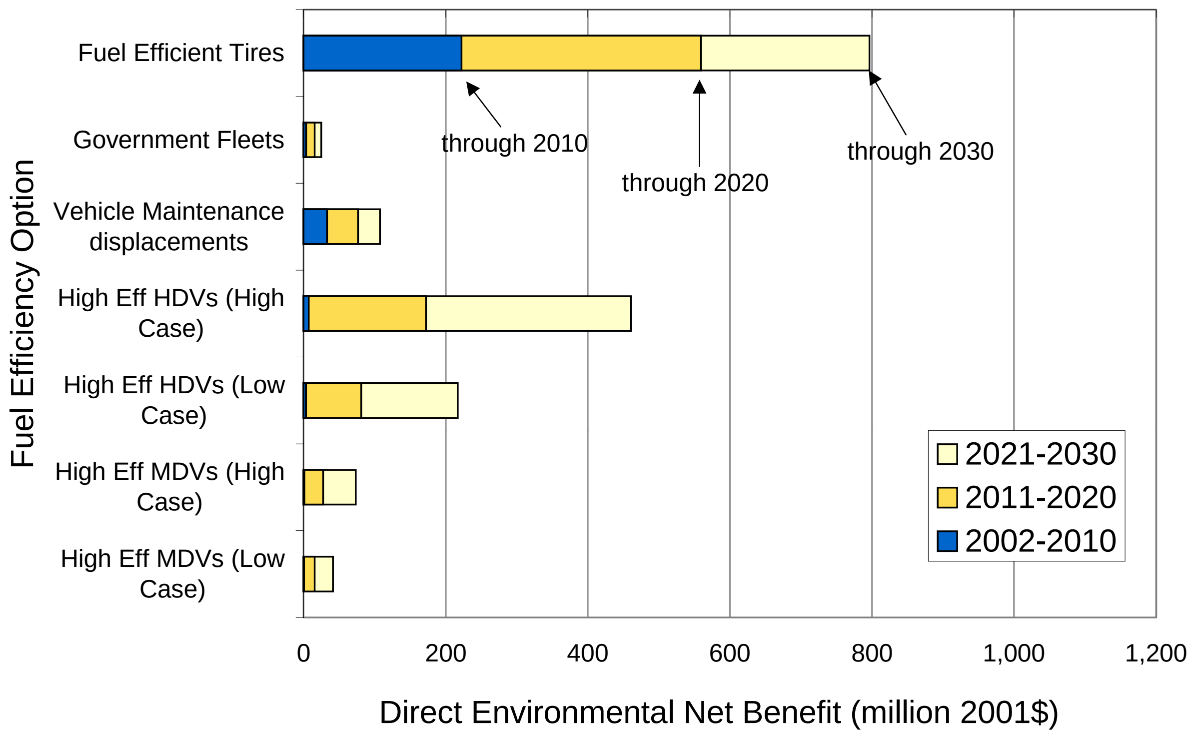



**Figure H-7. Group 1B-E DENB for 2002-2030**

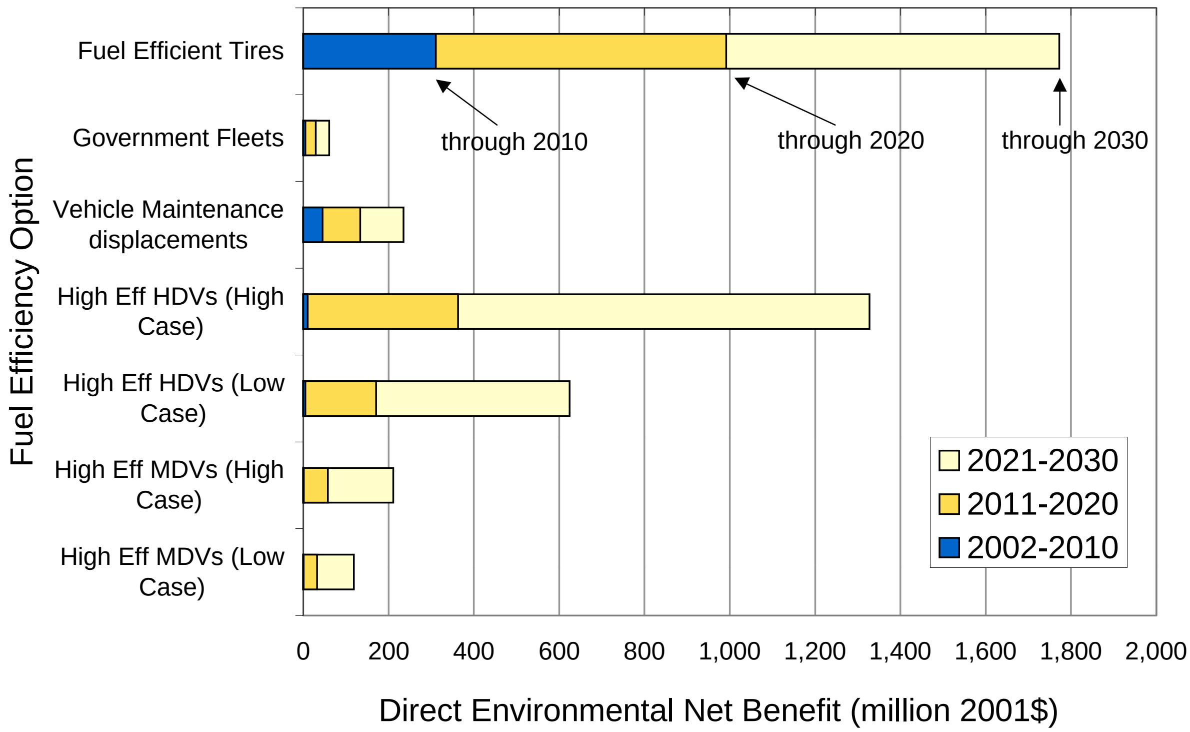



**Figure H-8. Group 1B-E DENB for 2002-2030 (No Discount)**

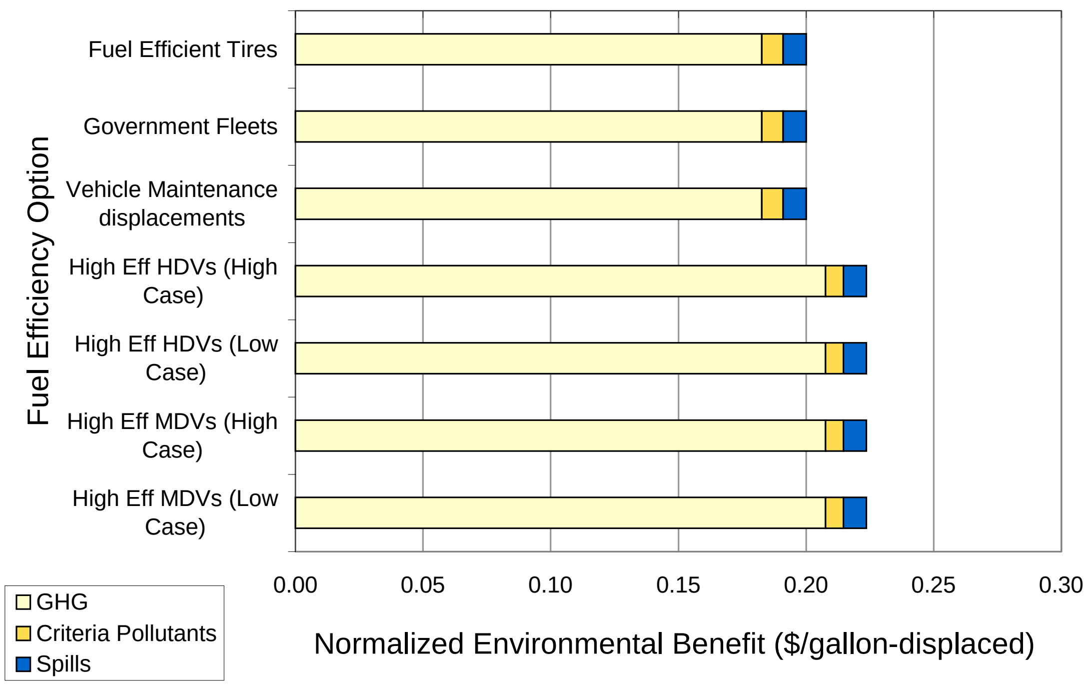



**Figure H-9. Group 1B-E DENB per Gallon Displaced in 2020**

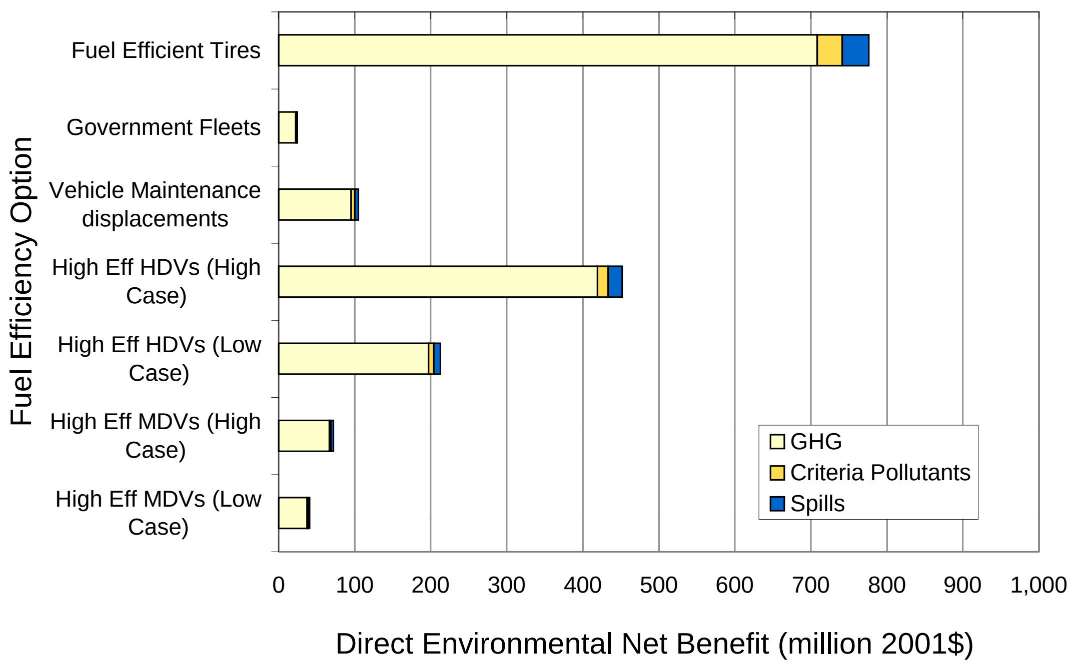



**Figure H-10. Group 1B-E Speciated DENB for 2002-2030**

Figure H-11 through H-20 show the DENB for the Fuel Displacement options — representing both the partial and full market penetration options within Group 2.

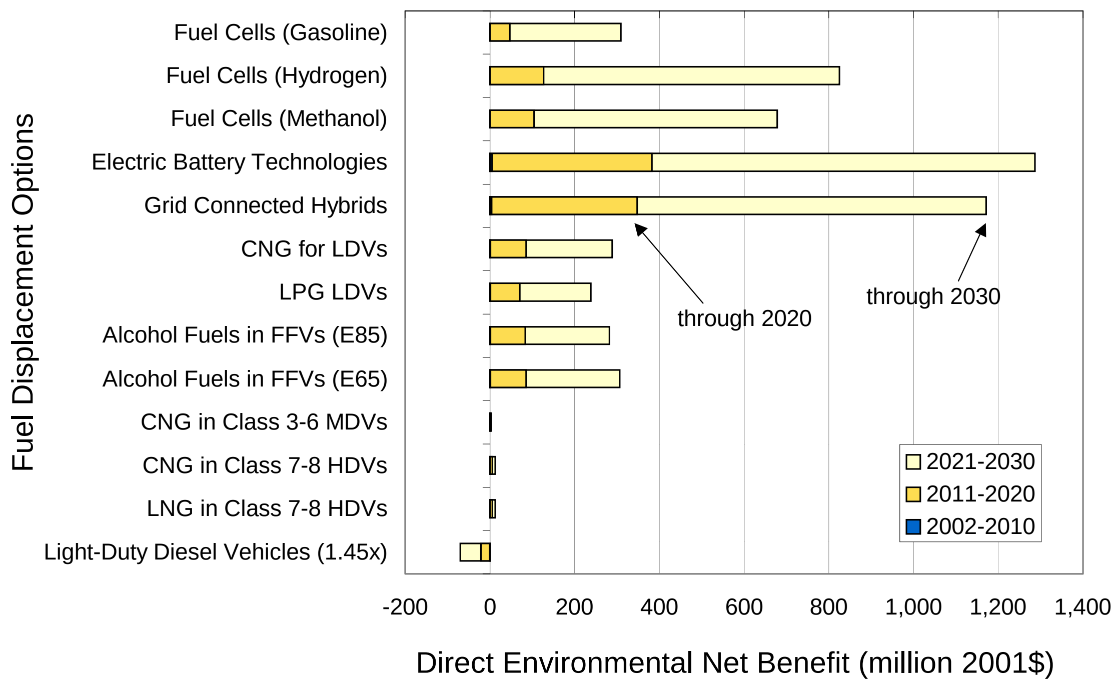



**Figure H-11. Group 2 DENB for 2002-2030 (Partial Market Penetration Options)**

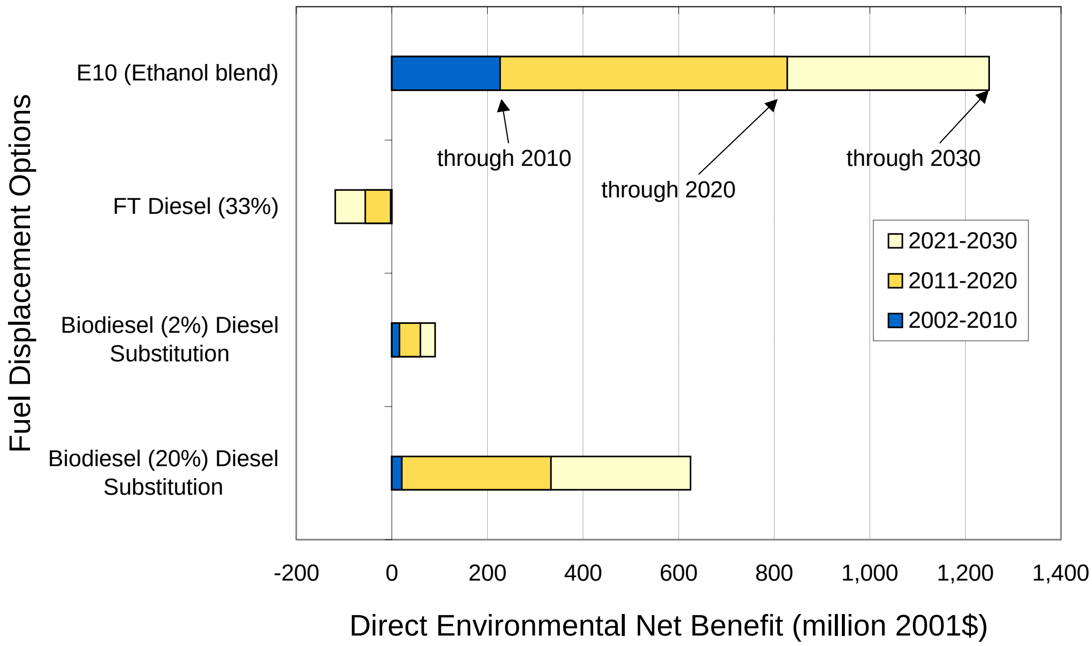



**Figure H-12. Group 2 DENB for 2002-2030 (Full Penetration Options)**

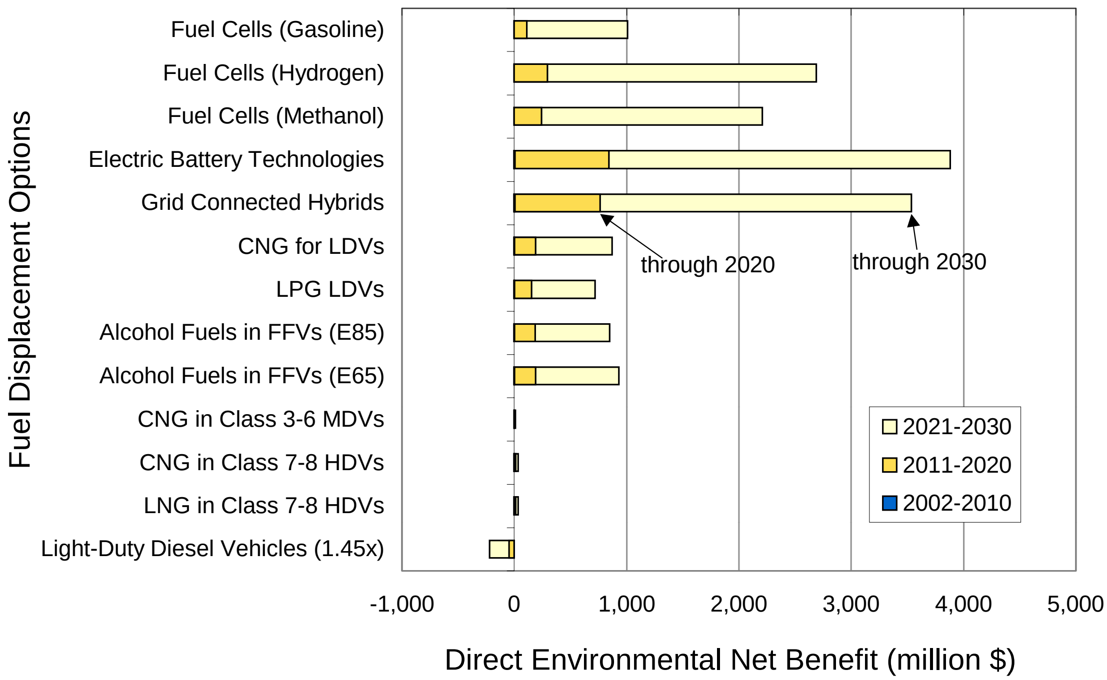



**Figure H-13. Group 2 DENB for 2002-2030 (No Discount, Partial Market Penetration)**

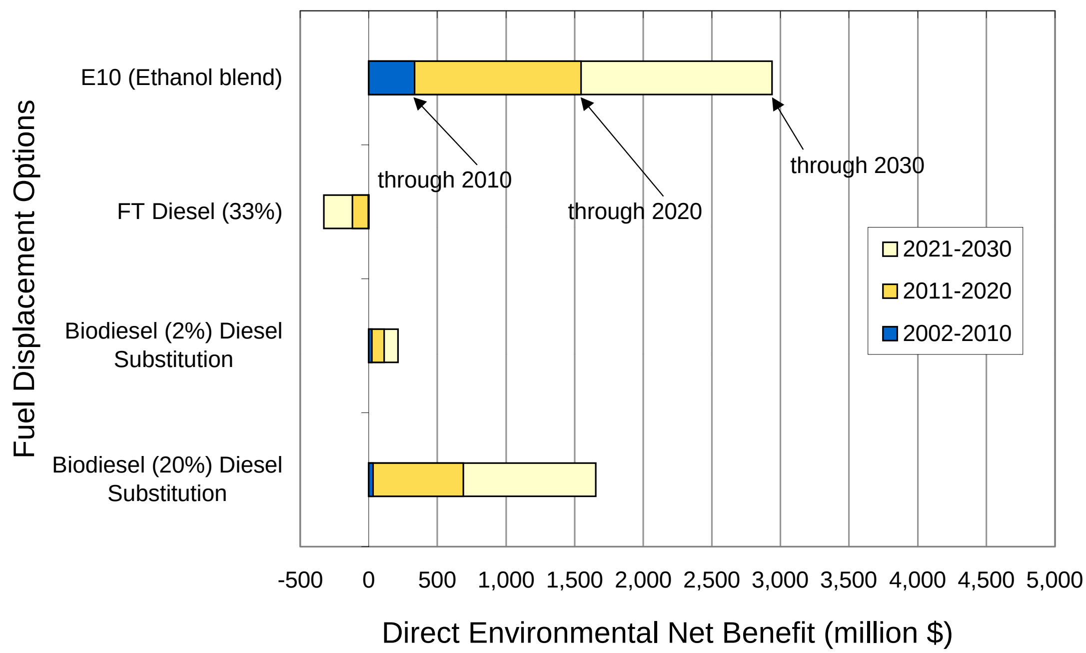



**Figure H-14. Group 2 DENB for 2002-2030 (No Discount, Full Penetration Options)**

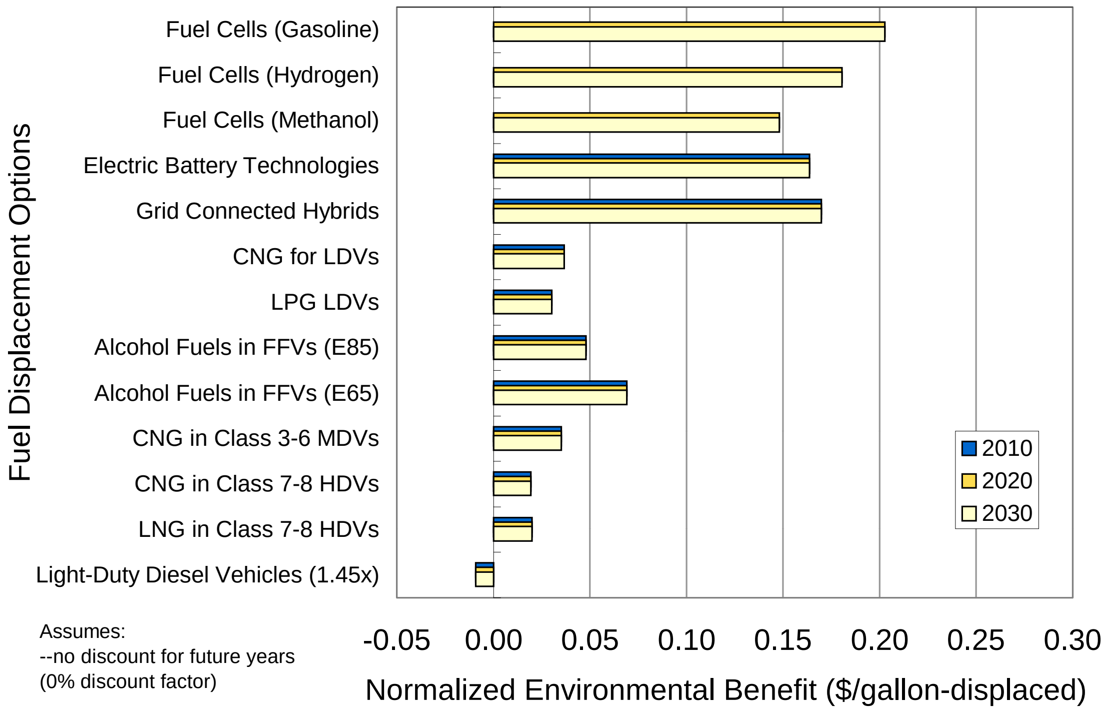



**Figure H-15. Group 2 DENB per Gallon Displaced (No Discount, Partial Market Penetration)**

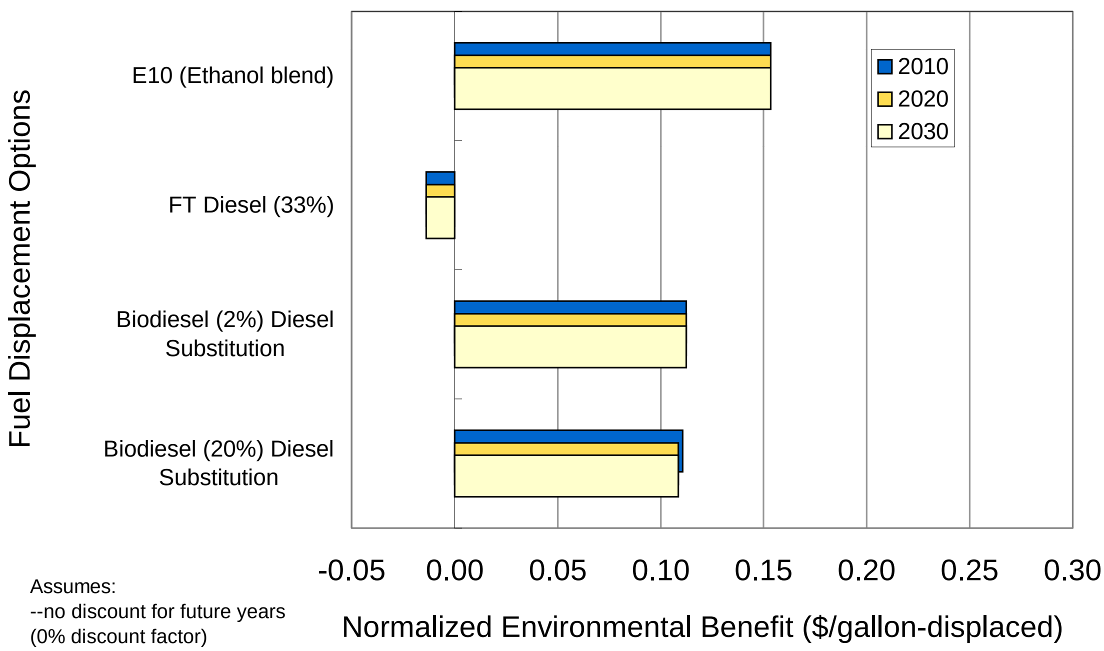



**Figure H-16. Group 2 DENB per Gallon Displaced (No Discount, Full Penetration Options)**

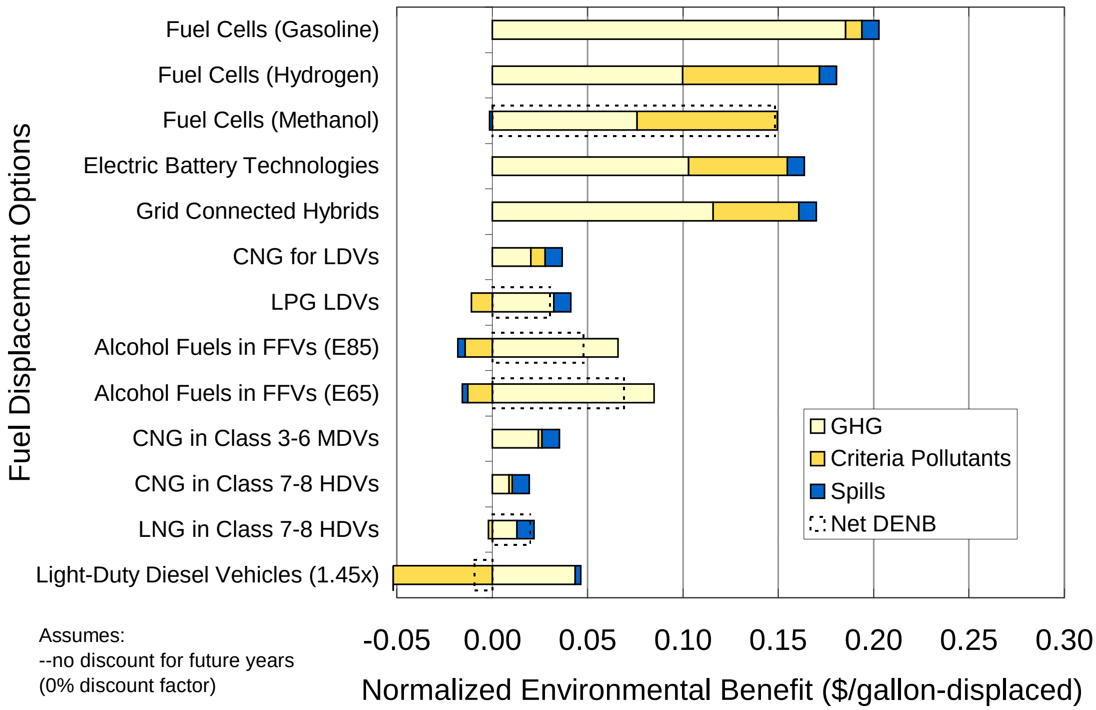



**Figure H-17. Group 2 Speciated DENB per Gallon Displaced (No Discount, Partial Market Penetration) in 2020**

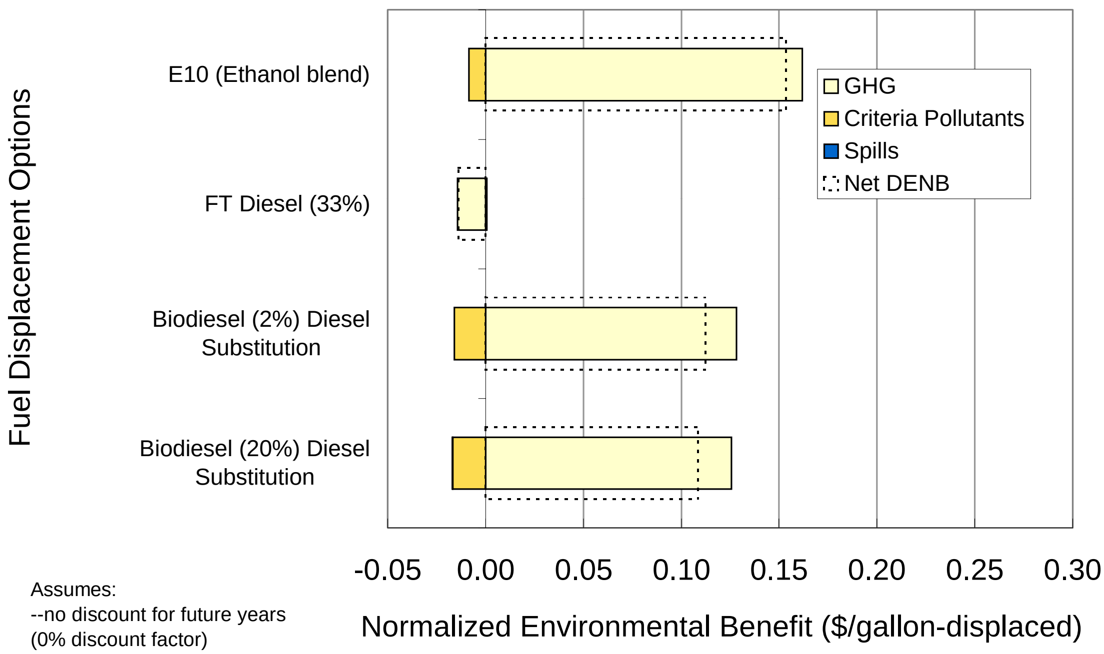



**Figure H-18. Group 2 Speciated DENB per Gallon Displaced (No Discount, Full Penetration Options) in 2020**

Figures H-19 and H-22 show additional DENB results for the Group 2 options speciated by type of DENB contribution.

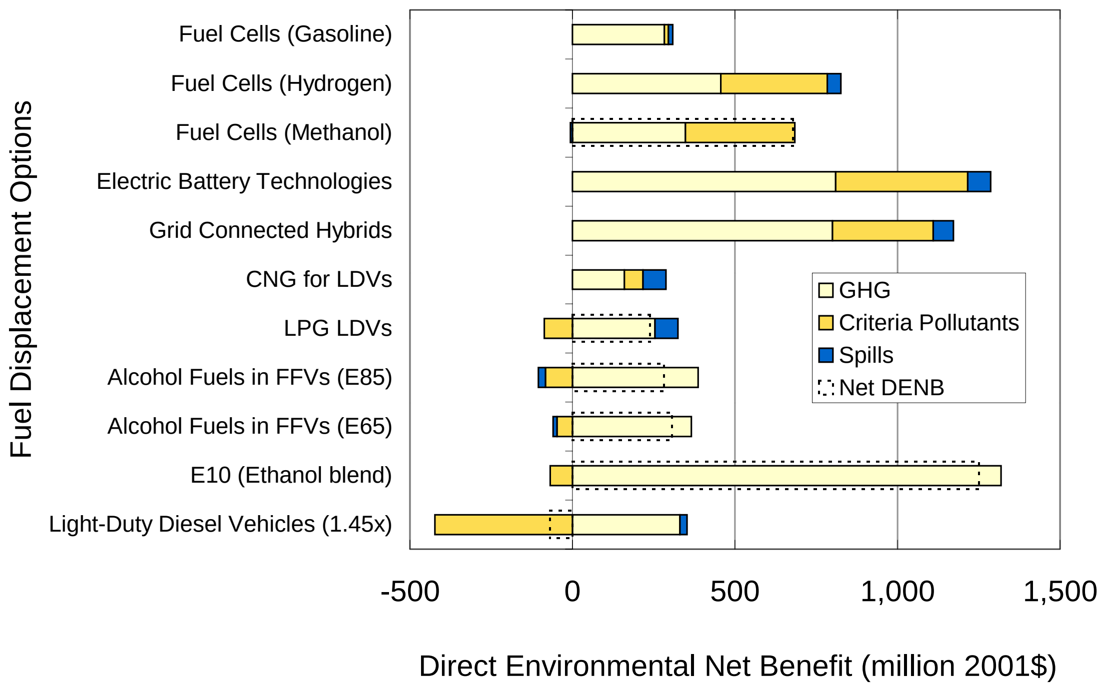



**Figure H-19. Group 2 Speciated DENB for Light-duty Vehicle Options in 2002-2030**

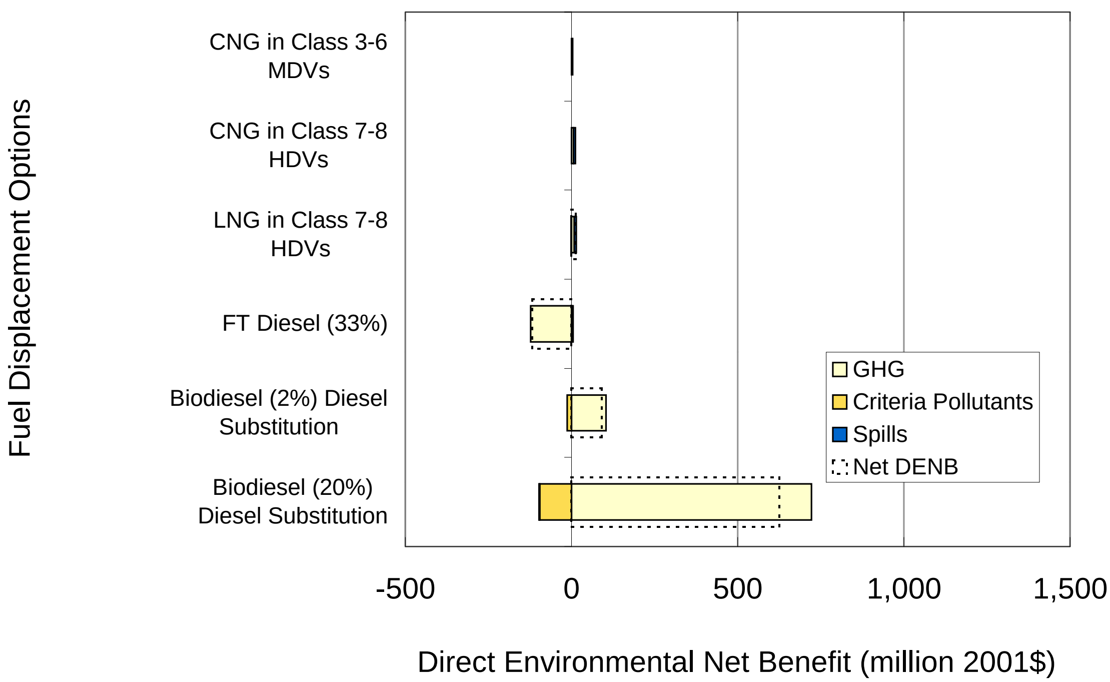



**Figure H-20. Group 2 Speciated DENB for Heavy-duty Vehicle Options in 2002-2030**

Figures H-23 through H-26 provide additional DENB analysis results for the Pricing options (Group 3).

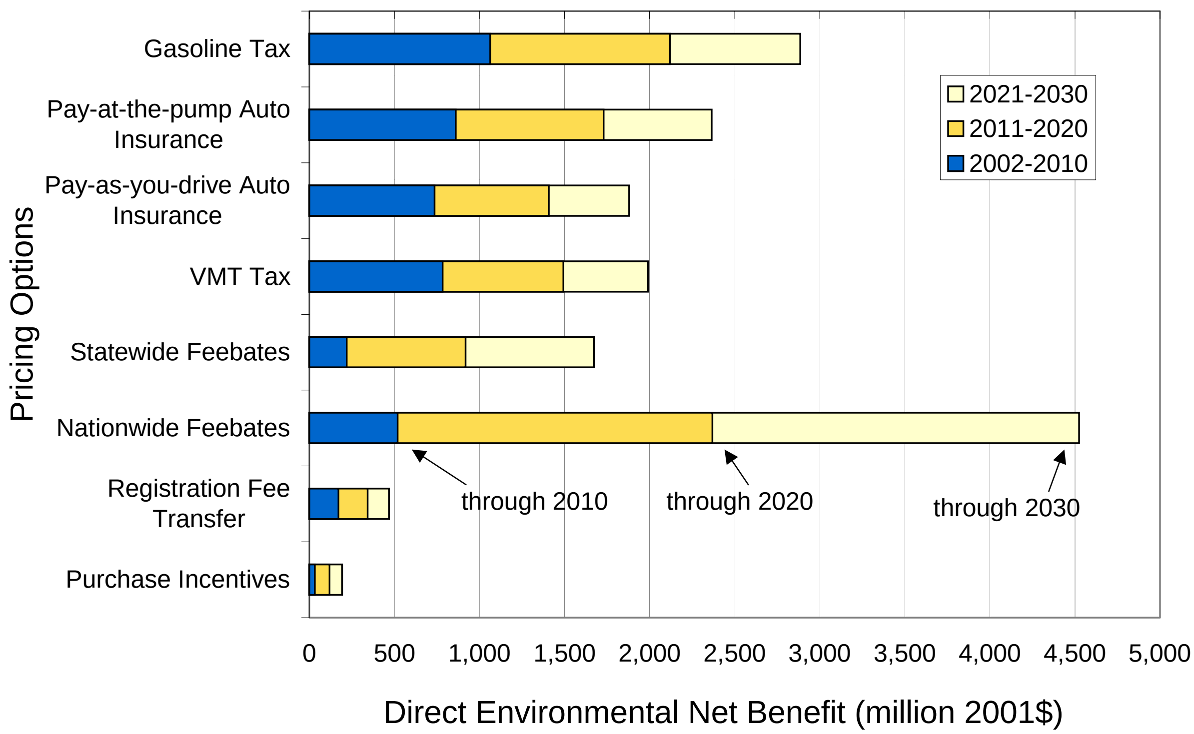



**Figure H-21. Group 3 DENB for 2002-2030**

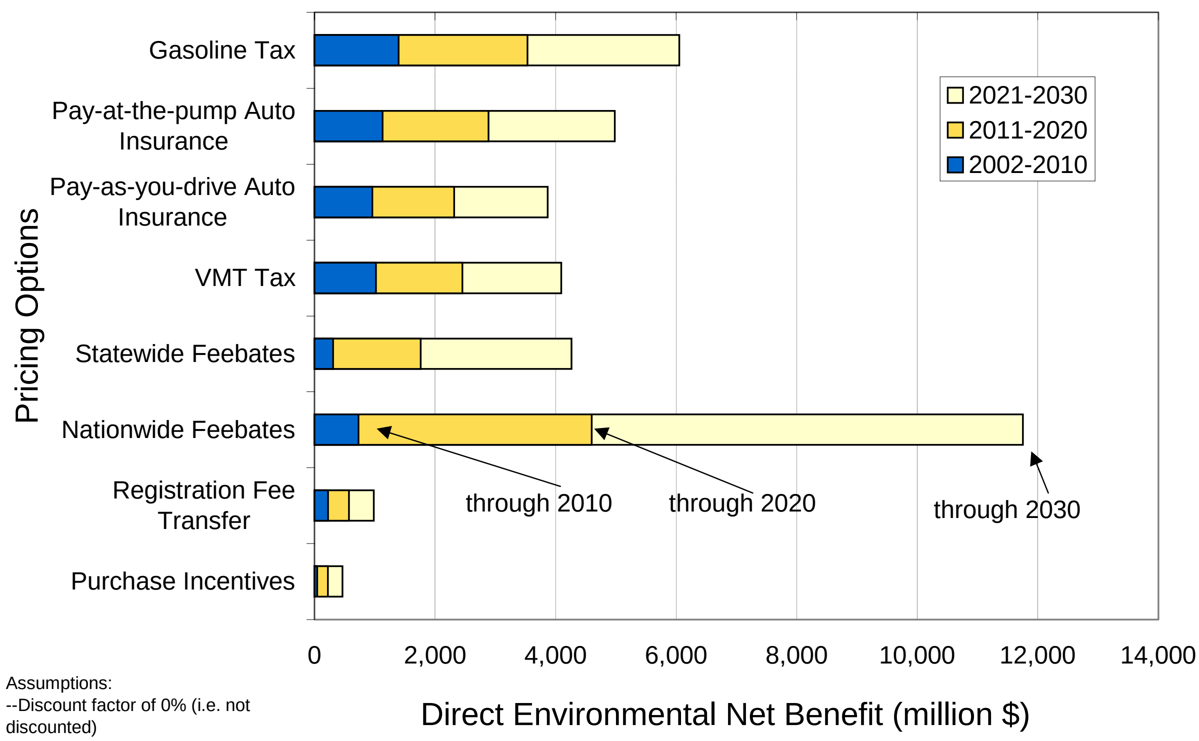
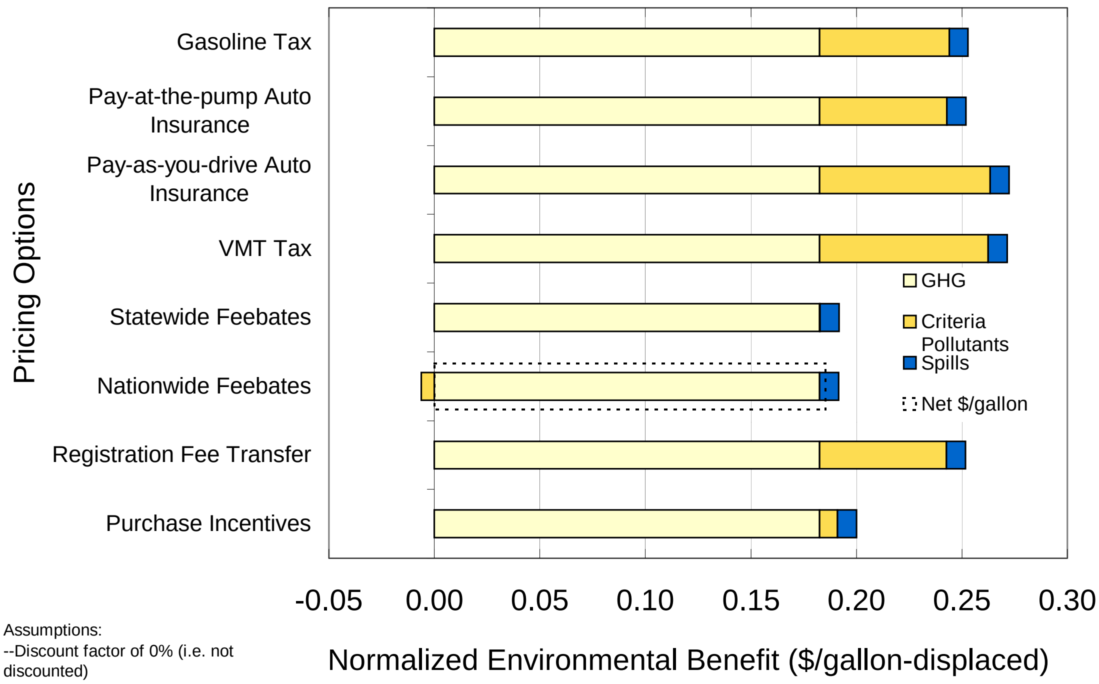



**Figure H-22. Group 3 DENB for 2002-2030 (No Discount)**




Assumptions:
--Discount factor of 0% (i.e. not discounted)

**Figure H-23.  Group 3 Environmental Benefit per Gallon Displaced in 2020 (No Discount)**

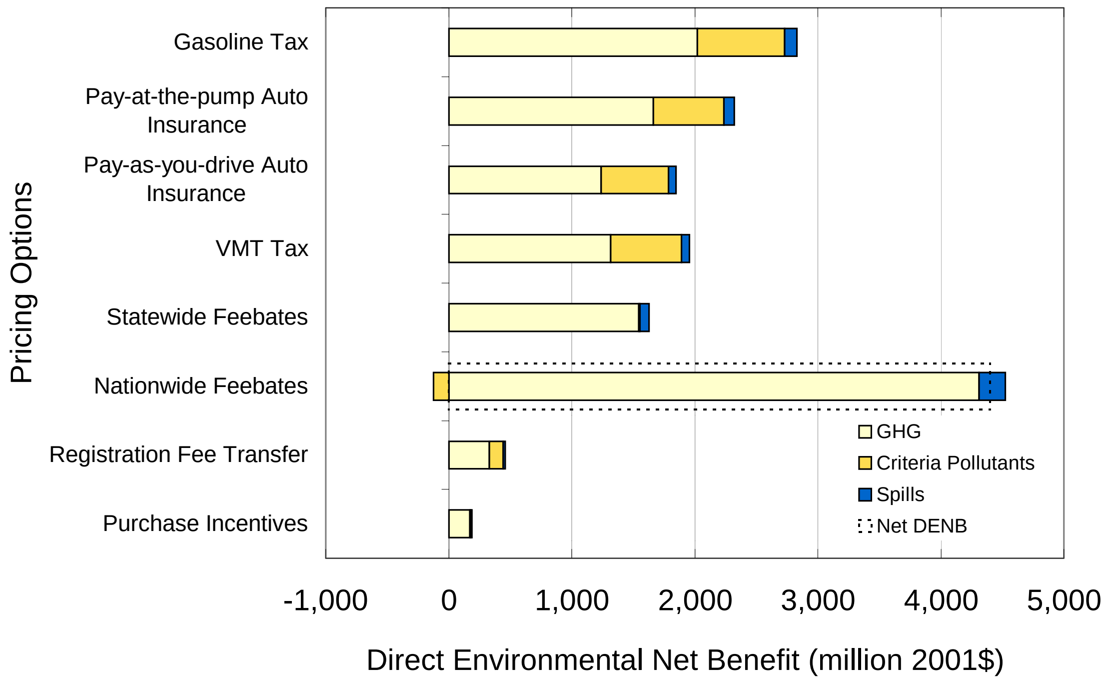



**Figure H-24. Group 3 Speciated DENB for 2002-2030**

## Appendix I. Summary of Public Comments and California Air Resources Board and TIAX Staff Responses

Set forth below is a summary of all comments that have not been incorporated into the final version of Benefits of Reducing Demand for Gasoline and Diesel, Volume 3, Task 1 Report. The explanation of why each comment was not incorporated into the final version follows each specific comment.

The majority of the comments received were incorporated into the final document. Many of these comments pertained to the transparency of the staff work and calculations as well as specific errors made by the staff, both technical and editorial. ARB and TIAX staff made significant modifications to the document to improve the transparency of the text and the tables. ARB and TIAX staff also corrected all errors that were indicated in comments submitted. The major changes to the Task 1 document made as a result of comments received include:

- The methodology used to determine the dollar value of reductions in pollutants was modified so that it is consistent. Originally, the value of reductions for some pollutants was based on cost to control while others were based on avoided societal damages. All are now valued based on avoided societal damages.

- Removal of the valuation of toxic air contaminants. As indicated in comments received, it is not possible to scale the dollar value of reducing toxic air contaminants to the dollar value of reducing PM as the various toxic air contaminants cause very different damages. Each toxic air contaminant must be evaluated individually to determine the dollar value of the damages associated with it. ARB and TIAX staff could find no information on the dollar value associated with toxic air contaminants other than PM and, as resources were limited, the valuation of toxic air contaminants was removed.

- The analysis of the value of diesel PM emission reductions relative to $PM_{10}$ or $PM_{2.5}$ reductions was removed. There is not sufficient, consistent, peer-reviewed evidence of the dollar value of reductions of diesel PM relative to $PM_{10}$ or $PM_{2.5}$. The current analysis values reductions of PM equally, regardless of whether it is diesel PM, $PM_{10}$ or $PM_{2.5}$.

Public comments were received from: Latham and Watkins and Gradient Corporation for International Truck and Engine Corporation; in the form of a joint letter from Center for Energy Efficiency and Renewable Technologies, Natural Resources Defense Council, Union of Concerned Scientists, Sierra Club, Coalition for Clean Air, American Lung Association of California, Planning and Conservation League, Steven and Michele Kirsch Foundation; Diesel Technology Forum; and, Western States Petroleum in the form of a letter to Gina Grey of Western States Petroleum from James M. Lyons of Sierra Research.

Comment: Fine particulate matter (PM) associated with CNG vehicles has a greater risk factor than diesel PM.

Response: Currently there is no standard for fine particulate. The risk associated with fine particulate and relative to diesel PM has not yet been officially quantified.

Comment: Estimates of benefits associated with technologies beyond the 2020 timeframe are too uncertain and should not be included in the report.

Response: Assembly member Shelley, the author of 2076 (Chapter 936, Statutes of 2000), directed staff to include a forecast of petroleum consumption to at least 2030. Many technologies that could provide significant reduction in California's dependence on petroleum may not be commercially viable by 2010 and/or may not be in widespread usage by 2020. A long-term vision was determined to be of value as our dependence on petroleum is a long-term, long-standing problem.

Comment: Task 1 does not reflect information that a decrease in vehicle weight could lead to and increase in vehicle fatalities.

Response: This subject is very controversial with no clear indication of a "scientific" winner. Some studies indicate that increased vehicle weight is associated with increased safety. However, there are also a number of studies that indicate that increased weight does not necessarily indicate increased safety and that the increase in the sale of heavier vehicles endangers passengers in lighter vehicles. Further, larger vehicles contribute to an increase in congestion, which also leads to increased accidents.

Comment: A broader view of health impacts needs to be included e.g. higher economy-wide costs lead to diminished economic activity, which, in turn, reduces life expectancy.

Response: There are a number of costs associated with reducing California's dependence on petroleum that were not included due to resources constraints. This report includes what ARB and TIAX consider to be the most influential and directly related costs associated with reducing petroleum dependency. The tertiary effects of reduced life expectancy described in this comment were considered too far removed, and therefore too uncertain, to include in this analysis.

Comment: Higher greenhouse gas emissions were assigned to diesel technologies than to gasoline, natural gas, and other technologies.

Response: This comment is incorrect as the Task 1 analysis indicates a greenhouse gas emissions benefit for diesel relative to gasoline, natural gas, and other technologies.

Comment: The market penetration estimates for light-duty diesel are understated and arbitrary.

Response: Currently, diesel vehicles make up a very small percentage of the light-duty fleet. Light-duty diesel vehicles are not currently sold in California in significant quantities and emission reduction hurdles still remain before they can be sold in California in the future. Further, it is unclear that the California public will purchase light-duty diesel vehicles in significant quantities. For these and other reasons, it is not possible to be certain what penetration rates may be for light-duty diesel vehicles of the future. CEC and ARB staff determined that a ten percent penetration rate was reasonable and allowed for equitable comparison between the light-duty diesel option and other options evaluated.

Comment: The estimate of $25 per ton benefit of reducing $CO_2$ is too low or too high, the direction was dependent on the commenter.

Response: The estimate of $25 per ton has been modified to be $15 per ton and is based on damage estimates in an effort towards consistency. Please refer to section 3 of the Task 1 report for a complete discussion of the valuation of $CO_2$.

Comment: The assumption that $CO_2$ is causing a significant increase in global warming has not been proven.

Response: The global warming effect is widely proven and accepted by most of the scientific community. Task 1 is not the forum for any discussions of the validity of global warming.

Comment: Volume of marine spills and data from the U.S. Coast Guard could be used to improve the cost estimates for clean-up of marine spills.

Response: Please refer to Appendix F (Joy verify this) for further discussion of the valuation of marine spills. Information from the U.S. Coast Guard as well as many other agencies and groups involved in marine spill clean-up efforts is included in the evaluation. Further refinement of marine spill clean-up costs is not considered advisable by ARB staff due to the relatively small impact of this estimate on the overall analysis.

Comment: Task 1 assumes the entire amount of the leaking underground storage tank (LUST) tax will be spent each year.

Response: Task 1 does not assume that the entire LUST tax will be spent each year, rather it is assumes that the entire amount will be collected each year.

Comment: There is evidence that light-duty diesel vehicles could emit at rates well below the 0.01 g/mi PM in-use emission rate assumed in Task 1.

Response: Although there is agreement that light-duty diesel vehicles equipped with a particulate trap will be significantly cleaner than today's light-duty diesel vehicles, the degree to which they will be cleaner and the deterioration associated with this technology will require further study and more data. ARB staff believes that future light-duty diesel vehicles may be able to meet the stringent 0.01 g/mi particulate standard in California. Whether production vehicles will emit at rates well below the PM standard, meet the standards for the other criteria pollutants concurrently, and their rate of deterioration, have yet to be determined. In fact, whether diesel vehicles will be trap-equipped in order to meet a 0.01 g/mi PM standard is still unknown. ARB staff is encouraged to hear that International is certain that light-duty diesel vehicles are capable of meeting emission rates far below the 0.01 g/mi particulate standard, and will be closely following the progress of this research. Any new information regarding the in-use performance of such vehicles will be taken into account in our ongoing regulatory programs.

Comment: The data used to estimate in-use PM emissions from gasoline vehicles in insufficient. There is data that suggests gasoline vehicles emit at levels higher than the 0.002 g/mi PM in-use emission rate assumed for light-duty gasoline vehicles in Task 1.

Response: To determine the in-use PM emissions from gasoline vehicles of the future, ARB staff evaluated data from the 1998 CE-CERT study, Measurement of Primary Particulate Matter Emissions from Light-Duty Motor Vehicles, which tested 129 gasoline vehicles and 19 diesel vehicles in California. This study has been peer-reviewed and is widely accepted as the most comprehensive study of PM emissions from vehicles in California in existence. Specifically, ARB staff evaluated PM emission rates from gasoline vehicles that emitted at or below 0.15 g/mi HC, 1.5 g/mi CO, and 0.2 g/mi NOx. There were nine such vehicles tested in the CE-CERT study. The purpose of this evaluation was to try to determine if there was some correlation between low non-PM criteria pollutant emissions and low PM emissions. ARB staff determined that those vehicles with low non-PM criteria pollutant emissions evaluated in the CE-CERT study also had lower PM emissions, relative to other vehicles in the study. The median PM in-use emission rate for the vehicles with lower non-PM criteria pollutants was below 0.002 g/mi. It should be noted that the non-PM criteria pollutant emissions from the vehicles in the CE-CERT study are significantly higher than the emission rates from partial-zero-emission vehicles (PZEVs). This is significant as the benefits associated with various light-duty options in Task 1 are determined relative to PZEV emission rates. Further, the vehicles in the CE-CERT study were not subject to the 150,000-mile emissions warrantee requirements for PZEVs. Therefore, the assumption that gasoline PZEVs will emit at approximately 0.002 g/mi PM is considered conservative by ARB staff.

Comment: The “rebound effect”, i.e. the effect of an increase in vehicle miles traveled (VMT) as a result of increased fuel efficiency, was not quantified in Task 1.

Response: There is much controversy over the size of the rebound effect in California, where congestion is a looming issue and income is so high that consumers, in general, do not limit their driving. Although it is likely there would be some rebound effect, there is no existing information that specifically quantifies the rebound effect of increased fuel economy in California in the future. ARB and CEC staff are currently working with outside experts to quantify the rebound effect given the above-mentioned reality and will revisit this issue as information arises.

Comment: All reductions of criteria pollutants should be valued, not just those that occur within California.

Response: ARB staff agrees that Task 1 tends to underestimate the benefits associated with criteria pollutant reductions because the benefits that occur out-of-state were not included. The decision to quantify only those criteria emission benefits that occur in-state was made for two reasons. First, there were limited resources and adding out-of-state benefits would have required resources that were not available. Second, as most of the benefits, over 80%, occur in-state it was determined that the in-state analysis was adequate. In the case of greenhouse gas emissions, most of the benefits will occur out-of-state due to the nature of the pollutants. Therefore, in order to capture the effects of reducing greenhouse gas emissions it was essential to evaluate benefits out-of-state.

Comment: Discounting the costs of greenhouse gases is inappropriate because it does not account for intergenerational equity.

Response: To simplify the analysis a five percent discount rate was used throughout. This rate is representative of the societal decision-making process in California. However, the five percent discount rate is likely too high for the long-term environmental benefits of reducing greenhouse gas emissions. For this reason, a lower bound of zero percent was evaluated and is included in Appendix H. Given the timeframe and resources allocated to this study, it was not possible to reach consensus on an appropriate discount rate for greenhouse gas emissions. In future analyses, this issue will be reexamined to determine which discount rate should be used.

Comment: The air emissions impact analysis for new vehicles should vary by year and by fuel type.

Response: Due to the stringency of new vehicle standards in the future, it is unlikely that either light- or heavy-duty alternative-fuel vehicles will emit at levels below the standards. Further, there is no reason to believe that more efficient vehicles will emit at levels below the standards. Thus, for alternative-fuel and more-efficient vehicles, there are no tailpipe or evaporative emission benefits relative to a conventional gasoline or diesel vehicle of the future. The only emission benefits attributable to these vehicles are the benefits associated with reducing upstream emissions due to the reduction in the amount of petroleum used.

Zero-emission vehicle technology types, such as battery-electric and fuel cell vehicles, will emit at levels below the standards. The methodology used in Task 1 underestimates the environmental benefits associated with zero-emission vehicle technologies because we assume that all light-duty vehicles meet the PZEV standards. (As there were no heavy-duty vehicle zero-emission technologies evaluated, this underestimation is not applicable to heavy-duty vehicle options.) The size of the underestimation and its effects are small and it was not possible, given the time and resource constraints, to modify the evaluation. However, any future analysis will account for fleet average vehicles rather than assuming all vehicles meet PZEV standards.

Comment: The economic model overestimates the negative impacts on California's economy from fuel efficiency. The model anticipates that fuel efficiency significantly reduces the demand for refined petroleum products. However, refineries already operating at full capacity can switch their production to other profitable products.

Response: See Appendix A. Even in the most aggressive strategy considered the economic model does not predict negative impacts on the overall California economy. Instead, consumers benefit because driving is cheaper. The economy benefits because consumer savings are spent elsewhere in the economy. Real personal income is constant and labor demand increases. It is true that the output of crude oil suppliers decreases due to draw down of California's resources and not the improvement in fuel efficiency. It is also true that California refiners' output drops compared to base years without fuel economy improvements, but it is not true that California refineries will not continue to operate at near full capacity. California refineries will continue to produce lower priced finished products than off shore sources due primarily to the higher transportation costs from off shore sources.

Comment: The EDRAM analysis in not consistent with the rest of Task 1, only addresses scenarios and not options, and only addresses policy scenarios beyond the control of the state.

Response: E-DRAM was used to determine if potential strategies would have a detrimental effect on the California economy. Most of the Task 1 effort assessed the damages associated with petroleum use. Based on this analysis benefits of petroleum reduction or substitution could be estimated for various petroleum reduction options. However, the effect of these options on the California economy could not be analyzed using the E-DRAM model for each of the options due to the costs of setting up and running this program. Instead, several strategies – which are combinations of options – were evaluated using the model to assess possible impacts to the California economy. Both the benefits assessment of various options and the assessment of California economic impacts are in fact very complimentary. The benefits assessment provides viable options that can be combined into petroleum reduction strategies. E-DRAM was used to verify the viably of these combinations, so that realistic petroleum reduction goals could be recommended as requested by the legislature.

It is immaterial that the petroleum reduction strategies may contain options beyond the control of the state. This analysis considered all viable options regardless of implementing authority. California could and should argue for improved vehicle fuel efficiency at the national level if improved fuel efficiency options are among the most cost effective measures to reduce petroleum dependency.